Oil
2025

Analysis and forecast to 2030

INTERNATIONAL ENERGY AGENCY

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Abstract

Global oil markets have so far had a turbulent 2025. Heightened trade tensions and uncertainty have weighed on the world economy and, by extension, oil demand growth. Combined with the recent OPEC+ decision to accelerate the unwinding of oil production curbs that have been in place for several years, these factors have recently pushed international oil prices to four-year low in April and early May. At the same time, shifts in energy policies are affecting oil producers and consumers alike, with oil supply security remaining high on the international energy policy agenda.

Oil 2025 looks beyond the short-term horizon covered in the IEA's monthly *Oil Market Report (OMR)* to provide a comprehensive overview of evolving oil supply, demand, refining and trade dynamics through 2030. This *Report* presents detailed forecasts and analysis of oil demand fundamentals across fuels, sectors and regions as well as the supply outlook from planned upstream and downstream projects around the world. The results provide valuable insights on the prospects for spare oil production capacity, product supply and trade flows through 2030. *Oil 2025* also explores the implications of surging output of natural gas liquids (NGLs) in an era of petrochemical-driven demand growth.

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Executive summary

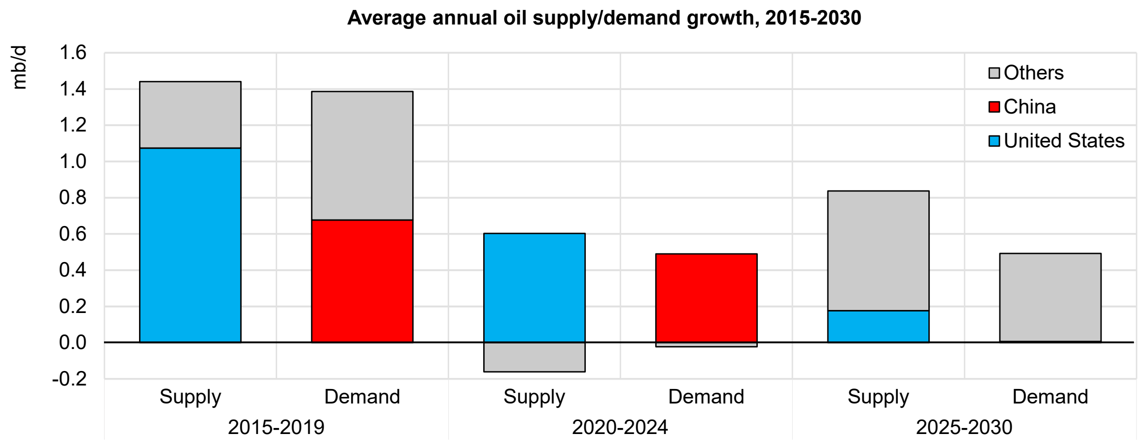
Turbulent times in oil markets

Heightened geopolitical risks, unresolved trade tensions, and policy shifts have added myriad uncertainties to the oil market outlook. Since the start of the year, major economic forecasters have cut their outlooks for world GDP growth in 2025 by roughly half a percentage point to around 2.8% and see a below-trend pace of about 3% annually for the remainder of the decade, with knock-on implications for oil demand. With conflicts in the Middle East region at risk of intensifying and trade negotiations ongoing, uncertainties surrounding our forecasts are substantial.

At the same time, a decision by the OPEC+ producer group, led by Saudi Arabia, to start unwinding oil production curbs in May 2025 is resetting oil supply trajectories over our 2024-30 forecast period. The anticipated output increase from OPEC+ and the impact of higher tariffs on trade pushed oil prices to four-year lows in April and early May. As a result, oil executives are recalibrating investment plans. However, oil prices have since rebounded after an exchange of air strikes between Israel and Iran started on 13 June 2025. With geopolitical and economic uncertainties affecting oil producers and consumers alike, oil supply security remains high on the international energy policy agenda.

Oil markets are going through a fundamental transformation as the drivers of global oil supply and demand patterns shift. Over the past decade, oil market dynamics have been defined by the parallel growth in US oil supply and Chinese oil demand.

US and China's shares in global oil supply and demand growth fade



From 2015 to 2024, the United States accounted for 90% of the increase in global supply, with the shale boom lifting US oil production by more than 8 mb/d to over 20 mb/d. At the same time, Chinese oil demand rose by nearly 6 mb/d, accounting for 60% of the global increase in oil use. The picture to 2030 looks very different. Following an extraordinary surge in EV sales, the continued deployment of trucks running on liquified natural gas (LNG), as well as strong growth in the country's high-speed rail network, along with structural shifts in its economy, Chinese oil demand is on track to peak this decade. For supply, the pace of expansion in US oil production is slowing as oil companies scale back investments but it nevertheless remains the largest contributor to non-OPEC+ growth in the forecast.

A peak in global oil demand is still on the horizon

Global oil demand is forecast to rise by 2.5 mb/d from 2024 to 2030, reaching a plateau around 105.5 mb/d by the end of the decade. However, annual growth slows from roughly 700 kb/d in 2025 and 2026 to just a trickle over the next several years, with a small decline expected in 2030, based on today's policy settings and market trends. This is driven by below-trend economic growth, weighed down by global trade tensions and fiscal imbalances, and the accelerating substitution away from oil in the transport and power generation sectors.

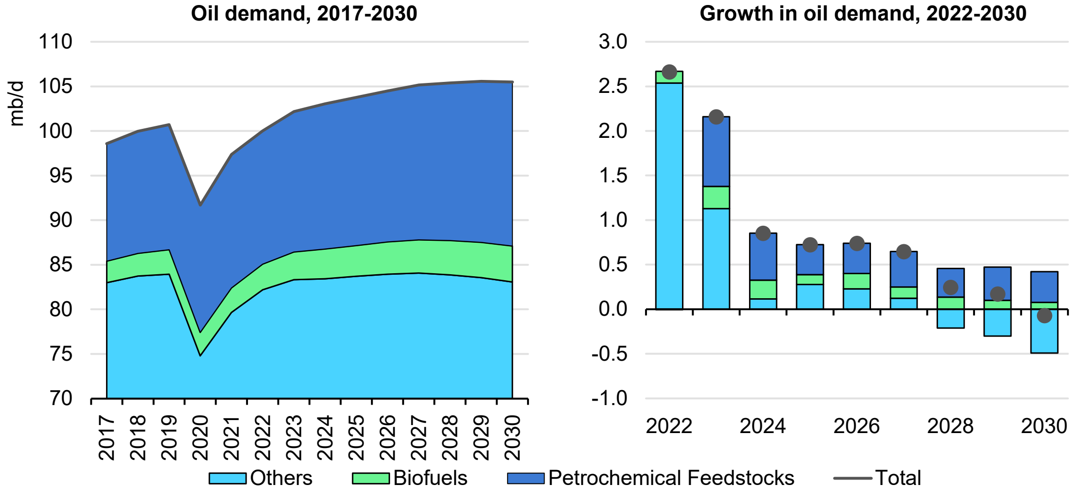
Despite some recent headwinds, global electric car sales have continued their remarkable growth trajectory. They exceeded 17 million in 2024 and are expected to surpass 20 million in 2025, representing around one-quarter of all cars sold, according to the IEA's Global Electric Vehicle Outlook 2025. This analysis shows that EVs are set to displace 5.4 mb/d of global oil demand by the end of the decade. Substitution away from oil will also feature prominently in power generation during the forecast period – particularly in Saudi Arabia, where displacement of oil burning by natural gas and renewables drives the single largest decline in oil demand for any country through 2030.

As the transport and power generation sectors continue to diversify towards other fuels, the petrochemical industry is set to become the dominant source of global oil demand growth from 2026 onwards. Increased petrochemical consumption is closely linked to the burgeoning supply of natural gas liquids (NGLs). China and the United States lead the build out of petrochemical capacity, at the expense of Europe and other economies in Asia. Globally, the production of polymers and synthetic fibres will require 18.4 mb/d of oil by 2030, or more than one in every six barrels. Demand for oil from combustible fossil fuels – which excludes petrochemical feedstocks and biofuels – may peak as early as 2027.

Robust oil demand growth of 4.2 mb/d in emerging and developing economies over the 2024-30 period contrasts with a continued contraction in advanced economies. Asian markets dominate growth, with India's expected 1 mb/d increase the largest of any single country by far, though rising oil use in Southeast Asian economies is also significant. By contrast, oil consumption among OECD countries is forecast to decline by 1.7 mb/d through 2030.

While the overall picture for global oil demand is broadly unchanged from last year's forecast, this masks notable changes among the world's two largest consumers. China's total oil consumption in 2030 is now set to be only marginally higher than in 2024, compared with growth of around 1 mb/d forecast previously. By contrast, lower gasoline prices and a loss of momentum in EV adoption in the United States, the world's largest oil consumer, have led to an increase in forecast oil demand of 1.1 mb/d by 2030 compared with last year's report.

World oil demand forecast to plateau this decade



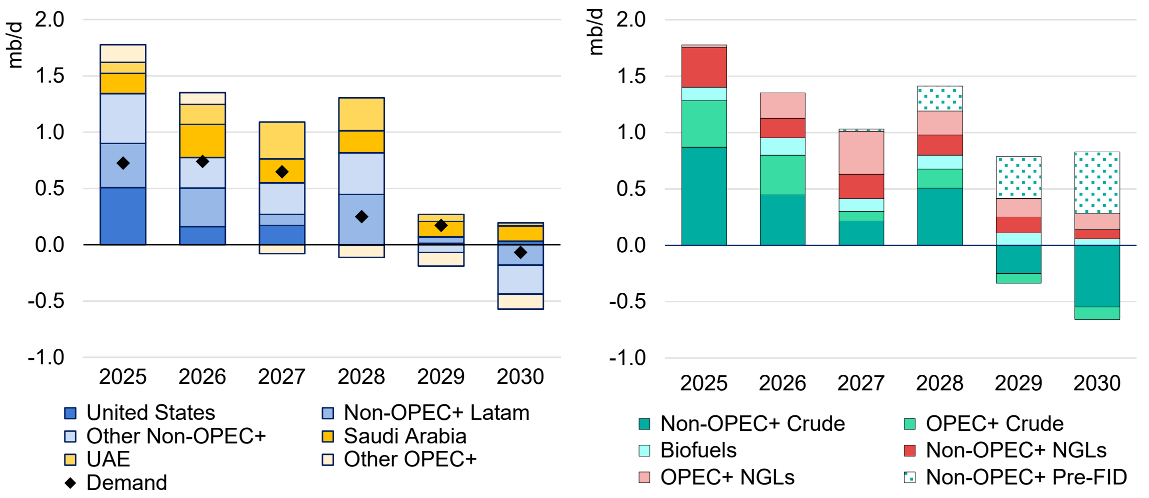
Lower oil prices set to slow upstream expansions

The precipitous drop in oil prices in the early months of 2025 and an uncertain investment climate have prompted oil executives around the world to reevaluate their upstream priorities. In addition, after nearly five years of production restraint, the OPEC+ alliance has begun to unwind voluntary supply cuts of more than 2 mb/d that have been in place since 2023. This has put additional pressure on producers outside the bloc to rebalance the market.

Upstream oil investment is set to fall by 6% to around USD 420 billion in 2025, with some of the largest declines in light tight oil in the United States. Investment in conventional projects – both existing and new – is expected to prove more resilient in 2025. Nonetheless, lower oil prices and higher production costs, due to tariffs and inflated costs for essential materials, could mean larger cuts to investment are still to come, while a return to durably higher prices could boost spending.

World oil production capacity is forecast to rise by 5.1 mb/d to 114.7 mb/d by 2030, led by Saudi Arabia and the United States – significantly outpacing the projected 2.5 mb/d increase in global oil demand. Mirroring demand trends, supply capacity growth is heavily frontloaded, slipping from 1.8 mb/d in 2025 to contraction after 2029 as the pipeline of non-OPEC+ projects wanes.

Global oil supply capacity forecast, year-on-year change, 2025-2030



Notes: OPEC+ NGLs include condensates. Crude includes processing gains and non-conventional volumes. The right-hand chart includes pre-sanctioned projects, listed in the Annex tables.

Global NGL production is expected to increase by 2.3 mb/d to 20.1 mb/d by 2030, accounting for nearly half the total increase in world oil production capacity. A strategic focus on natural gas developments by producers in the Middle East is projected to boost regional NGL supply by 1.4 mb/d to 2030. While independent US producers are set to slow spending, increasing associated gas from the shale patch is expected to buoy US NGL output by 860 kb/d. Biofuel supply gains led by Brazil, India and Indonesia are forecast to add another 680 kb/d by 2030. Crude oil capacity is set to rise by 1.8 mb/d globally, led by the United Arab Emirates (+720 kb/d) and Iraq (+560 kb/d), while the biggest decline comes from Mexico.

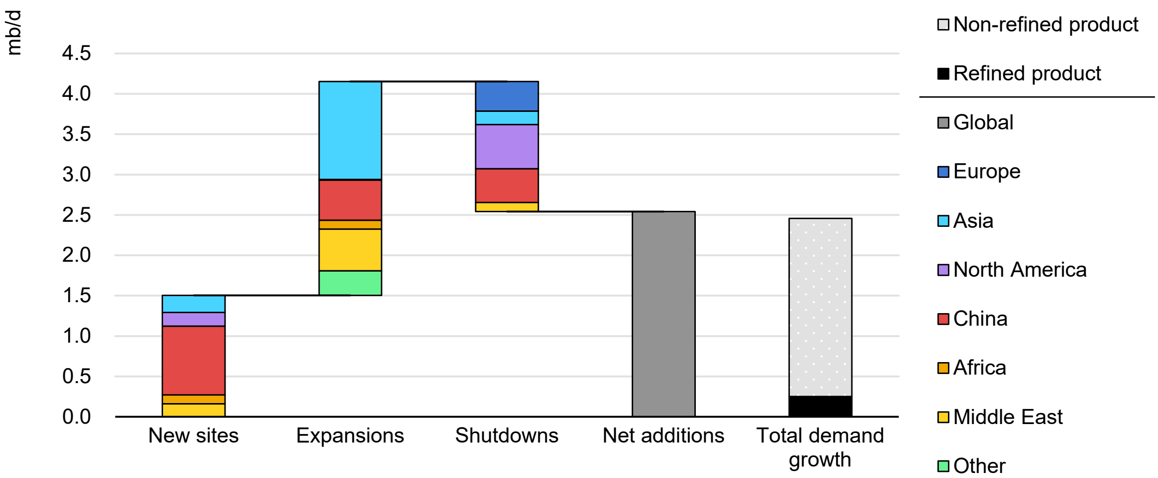
Total non-OPEC+ oil supply is forecast to climb by 3.1 mb/d by 2030, despite the number of approved projects tailing off after 2027. The Americas dominate the expansion even though the outlook for US and Brazilian production has dimmed. Combined with a forecast slowdown in oil demand, the call on OPEC+ crude in 2030 is 1.2 mb/d below the average 2025 call. If OPEC+ crude oil supply is sustained at current rates, all else being equal, global oil supply would rise to 107.2 mb/d by 2030, 1.7 mb/d higher than projected demand, suggesting prices would have to drop to prevent an untenable stock build.

The refining industry faces tepid growth for products

The refining sector is set to be increasingly challenged by demand growth that is underpinned almost exclusively by petrochemicals produced from non-refined products such as NGLs. Global refined products demand is projected to peak in 2027 at 86.3 mb/d, only 710 kb/d above 2024 levels. Thereafter, accelerating declines in gasoline and diesel use outweigh growth in naphtha and jet fuel.

Despite tepid demand growth projections, 4.2 mb/d of new refining capacity is expected globally by 2030, partly offset by 1.6 mb/d of closures. Even so, net capacity growth is set to far exceed refined product demand, with increases in Asia, especially China and India, outpacing shutdowns in Europe and the United States. This indicates that more capacity will have to shut, with high-cost plants in Europe and on the US West Coast expected to be hardest hit.

Refinery expansion and closures, and demand growth, 2024-2030



Note: Refined product demand net of CTL/GTL, additives, biofuels, NGLs and direct use of crude.

Rising oil demand in Asia boosts long-haul oil imports

With European and US refining activity set to slow over the remainder of the decade, and with oil supply in the Americas continuing to expand, the Atlantic Basin crude surplus is expected to widen by approximately 870 kb/d to 7.1 mb/d by 2030. Atlantic Basin product exports are poised to rise by 320 kb/d to 3.5 mb/d, as regional demand for refined products contracts more rapidly. Meanwhile, East of Suez refinery activity will not keep up with the rise in refined product demand, marginally widening the product supply gap. Even so, the Middle East is projected to contribute an additional 860 kb/d to global product supply through 2030, further consolidating its role as a key export-oriented refining hub.

Demand

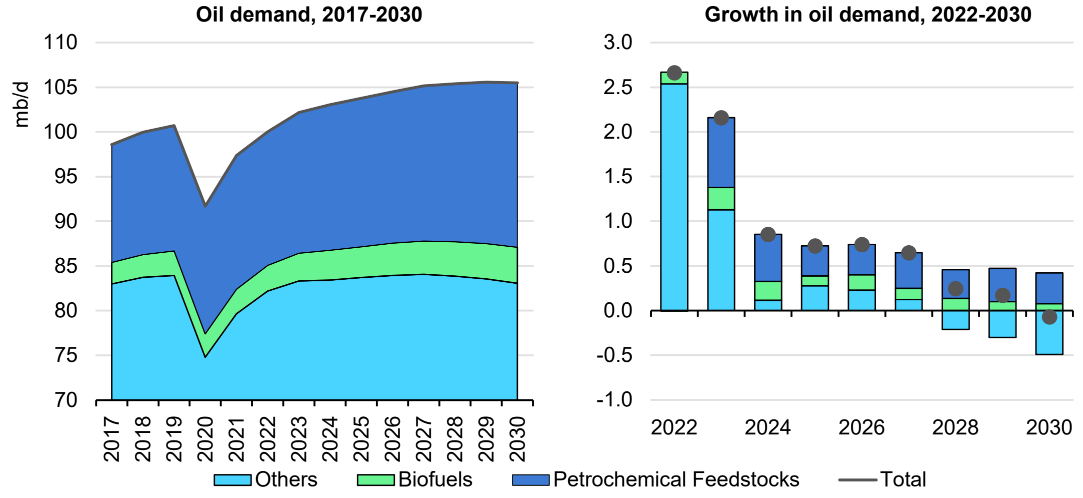
Global summary

World oil demand plateauing amid structural changes

Global oil demand is forecast to increase by an aggregate 2.5 mb/d over our 2024-30 outlook period, to reach 105.5 mb/d by the end of the decade. However, these gains are strongly front-loaded, with growth slowing from around 720 kb/d in 2025-26 to a mid-period plateau, before entering a narrow contraction in the final year. Subpar economic growth and the accelerating substitution away from oil in the transport and power generation sectors are the main structural drivers of this slowdown.

Petrochemicals, led by the steady increase in global natural gas liquids (NGLs) supply, and a continued shift towards biofuels account for the overwhelming majority of growth from 2026 onwards. As a result, demand for oil from combustible fossil fuels – which excludes petrochemical feedstocks and biofuels – looks set to plateau at around 84 mb/d. As a consequence, CO_2 emissions from oil use are now forecast to hit an apex by 2027.

World oil demand forecast to plateau this decade



Emerging economies will account for the entirety of additional demand growth. Amid broad expansion across the product spectrum, non-OECD oil demand is set to rise throughout the forecast period, by an average 1.2% per year, for total gains of 4.2 mb/d. Asian countries will dominate growth, with India's 1 mb/d increase the largest of any country by far.

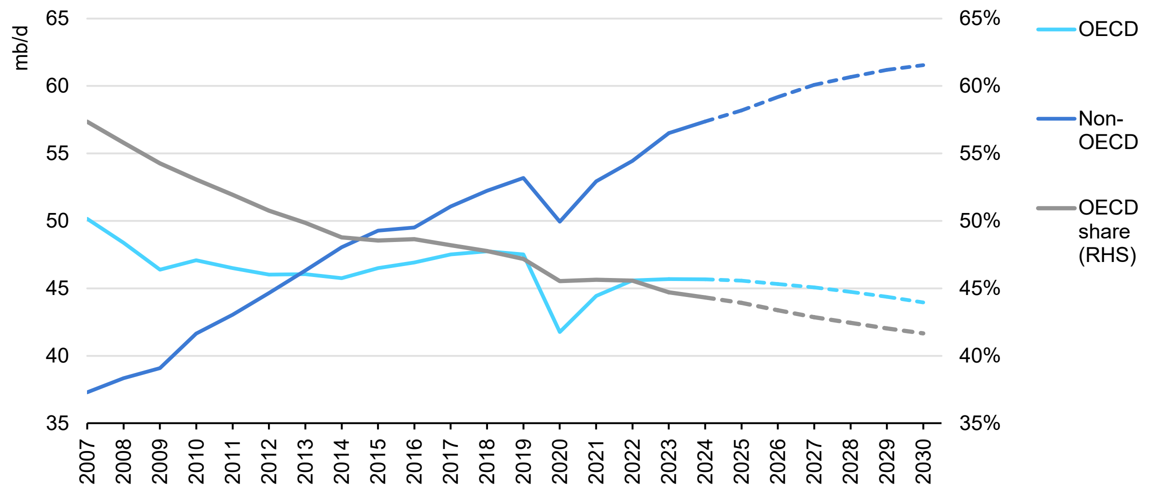
World oil demand by region, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
North America	24.9	21.9	23.7	24.3	24.6	24.5	24.6	24.5	24.4	24.3	24.1	24.0	-0.4%	-0.6
S&C America	6.7	5.7	6.3	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.4	7.4	1.4%	0.6
Europe	15.8	13.7	14.4	14.9	14.8	14.9	14.9	14.8	14.6	14.5	14.3	14.1	-0.8%	-0.7
Africa	4.2	3.9	4.4	4.5	4.6	4.6	4.8	4.9	5.0	5.2	5.3	5.4	2.9%	0.9
Middle East	8.9	8.3	8.6	9.1	9.2	9.2	9.4	9.5	9.6	9.6	9.4	9.2	-0.1%	0.0
Eurasia	4.3	4.0	4.3	4.4	4.4	4.3	4.4	4.4	4.5	4.6	4.6	4.6	1.1%	0.3
Asia Pacific	36.0	34.2	35.6	36.3	38.0	38.6	38.9	39.4	39.8	40.1	40.4	40.7	0.9%	2.0
World	**100.7**	**91.7**	**97.4**	**100.0**	**102.2**	**103.0**	**103.8**	**104.5**	**105.1**	**105.4**	**105.6**	**105.5**	**0.4%**	**2.5**
Annual change	**0.7**	**-9.0**	**5.7**	**2.7**	**2.2**	**0.9**	**0.7**	**0.7**	**0.6**	**0.2**	**0.2**	**-0.1**		

Conversely, OECD oil consumption, having completed its post-pandemic rebound in 2023, will decline by a net 1.7 mb/d from 2024 to 2030. Progress in the region's vehicle fleet transition and structurally weak economic growth weigh on transport and industrial fuels alike, with gasoil and gasoline consumption falling by around 1 mb/d each. Only LPG/ethane and jet/kerosene will be able to escape the general bearishness, with annual growth rates of around 1% each. As a consequence, the group's share of global oil use will fall to 42% in 2030, from 44% in 2024, having dropped below 50% in 2013.

Underscoring the ever-growing importance of the petrochemical sector, naphtha and LPG/ethane will account for 24% of total oil demand in 2030 compared to 22% in 2024 and 20% in 2019, LPG/ethane's growth will be the highest among products in both regions.

OECD and non-OECD oil demand, 2007-2030



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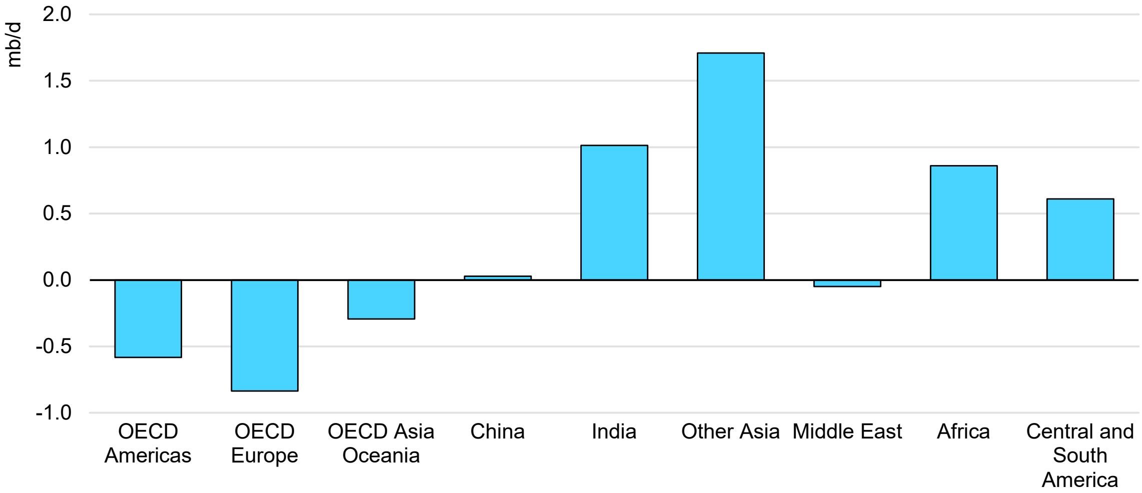
While the overall global demand growth trajectory is broadly similar to last year's Oil 2024, this masks offsetting shifts in individual countries, especially the United States, the People's Republic of China (hereafter, "China") and Saudi Arabia. In our current forecast, Chinese oil demand will rise by a very modest 30 kb/d, concluding the decade at 16.7 mb/d, compared to the 18.1 mb/d expected last year. This downward adjustment mainly reflects EV sales charging ahead at breakneck speed, eclipsing last year's assumed pace, driven by new policy initiatives introduced to hasten the uptake of EVs as part of the country's wider economic stimulus measures announced in 2024. By contrast, US oil demand in 2030 has been upgraded by 1.1 mb/d to 20 mb/d, as a faster GDP growth outlook this year (2.1% vs. 1.7%) and lower pump prices combine with a significant loss of projected momentum in EV adoption to boost gasoline demand. In addition, the substitution away from oil in power generation is accelerating, led by Saudi Arabia. The country's aggressive plans to phase out oil use in its electricity sector in favour of natural gas and renewables will slash oil burn in power generation by 1 mb/d over the forecast, offsetting growth in other products and resulting in Saudi Arabia's consumption falling by 620 kb/d – the largest decline in oil demand in absolute terms for any country in the 2024-30 outlook.

Foremost among the assumptions underlying our demand forecasts are economic growth, oil prices and EV adoption. For each of these factors, the recent escalation in trade tensions augurs a protracted period of heightened uncertainty. This pertains especially to the unsettled global regulatory and policy environment, with domestic and international governing directives, such as EV subsidies and tariff measures, affecting all three concurrently. Considering projected global oil consumption's relatively limited gains, even minor changes in these variables would materially shift the timing and gradient of this trajectory.

Growth in world oil demand by selected countries and regions, 2024-2030



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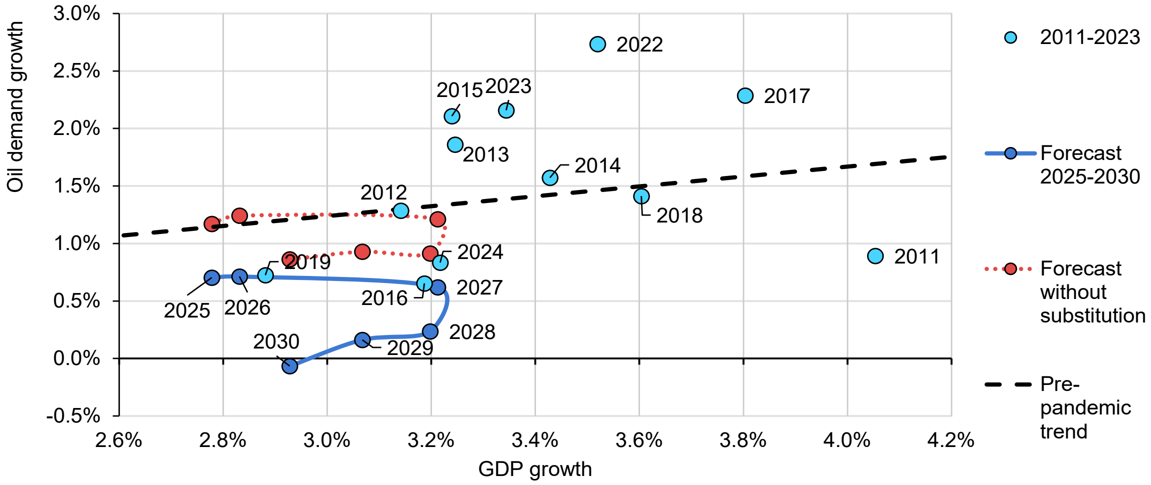
GDP still drives oil demand but decoupling already underway

Our GDP outlook, with average global growth of about 3.0% over the forecast period, incorporates a significant regional disparity, with the OECD's annual rate of 1.8% only half the non-OECD's 3.9% pace. The global rate is almost half a point below the 2010s trend, as adverse demographics and deglobalisation undermine the outlook for economic growth and trade. This deceleration is especially sharp in China – its annual GDP expansion is almost four points lower than in the 2010s – amid myriad structural demographic and economic challenges.

With the pandemic period (when public health policy upended oil demand) now concluded, GDP has reasserted its traditional role as the key determinant of oil use – albeit only briefly. Oil consumption increases in 2025 and 2026 are roughly in line with the level implied by (subpar) GDP growth. However, this long-standing relationship subsequently diminishes, with oil demand forecast to flatline and then move towards a small contraction by the end of the decade as substitution away from oil in transport and power generation increasingly offsets GDP's contribution.

Growth in global oil demand and GDP, 2011-2030



Note: Excludes 2020 and 2021 due to Covid-19 distortions.
Source: IEA analysis based on data from Oxford Economics.

Emerging Asia and petrochemicals power global gains

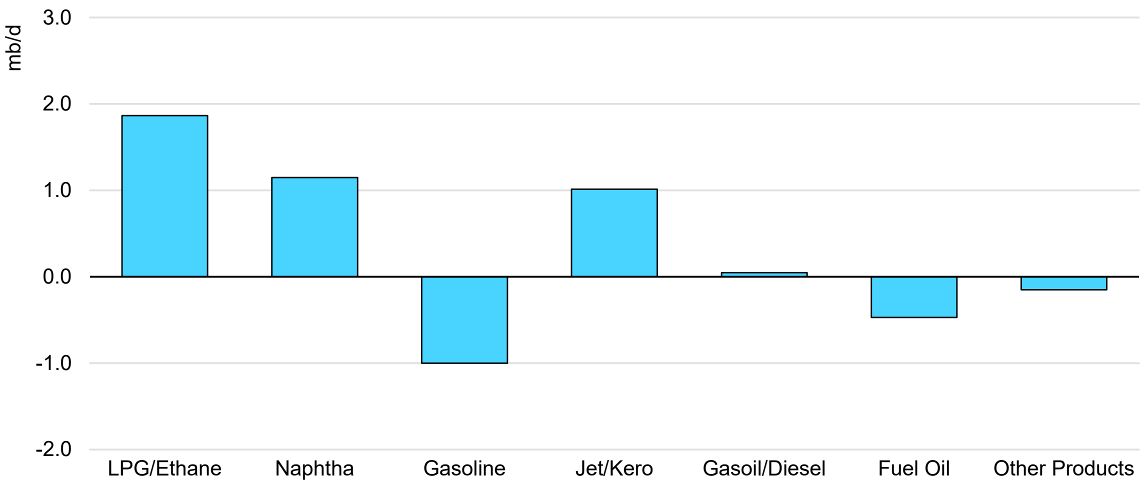
The substitution of oil by electrification is particularly prominent in the transport sector, where liquid fuels consumption is already plateauing. Despite slowing penetration in some advanced economies, global electric car sales will continue to increase sharply as China's extraordinary EV sales momentum consolidates. Rising EV use is forecast to displace more than 5 mb/d of gasoline and diesel consumption globally by 2030. Post-Covid behavioural shifts further depress the outlook for oil demand in transport. Teleworking, now entrenched in advanced economies, saved around 800 kb/d in transport fuel during 2024, compared with 2019. Public transport use has been similarly transformed by the pandemic, with mass transit ridership remaining well below 2019 levels in many major western cities. Here too, China's post-reopening mobility boom eclipses the recovery in other countries, with its public transport rebounding at a much faster pace.

World oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	13.2	13.3	13.6	14.2	14.6	15.1	15.4	15.6	16.1	16.4	16.7	17.0	2.0%	1.9
Naphtha	6.7	6.6	7.0	6.8	7.1	7.3	7.5	7.8	7.9	8.1	8.2	8.4	2.5%	1.2
Gasoline	26.9	23.9	26.0	26.6	27.1	27.2	27.4	27.3	27.2	27.0	26.7	26.2	-0.6%	-1.0
Jet/Kerosene	7.9	4.6	5.2	6.1	7.2	7.6	7.7	7.8	8.0	8.2	8.4	8.6	2.1%	1.0
Gasoil/Diesel	28.7	26.7	28.2	28.7	28.4	28.3	28.3	28.4	28.5	28.5	28.4	28.3	0.0%	0.0
Residual fuel oil	6.2	5.8	6.3	6.5	6.5	6.5	6.5	6.5	6.4	6.3	6.2	6.1	-1.2%	-0.5
Other products	11.1	10.8	10.9	11.2	11.2	11.0	11.0	11.0	11.0	11.0	11.0	10.9	-0.2%	-0.2
Total products	**100.7**	**91.7**	**97.4**	**100.0**	**102.2**	**103.0**	**103.8**	**104.5**	**105.1**	**105.4**	**105.6**	**105.5**	**0.4%**	**2.5**
Annual change	**0.7**	**-9.0**	**5.7**	**2.7**	**2.2**	**0.9**	**0.7**	**0.7**	**0.6**	**0.2**	**0.2**	**-0.1**		

Oil use in aviation and marine shipping has so far been relatively insulated from the direct substitution of electrification and other non-oil alternatives impacting the road fuels. However, a reasonably constructive underlying demand outlook for both sectors will be substantially eroded by fuel efficiency gains. As a result, jet/kerosene use may not regain its pre-Covid levels until 2027 – four years after flight activity passed the same mark. At the same time, emission standards mandated by the United Nations' (UN) International Maritime Organization (IMO) will cause bunkering growth to flatline.

Growth in world oil demand by product, 2024-2030



On a sectoral level, petrochemical feedstocks are set to continue their domination of global demand growth. Subject to fewer structural headwinds than the major transport fuels, we estimate that the production of products like polymers and synthetic fibres will require 18.4 mb/d of oil in 2030, or more than one in every six barrels used globally. Almost half of the uplift will come from ethane or LPG and the petrochemical sector remains the major end user of burgeoning NGLs supply.

Feedstocks will also be the major growth catalyst of China's oil demand, with their 1.1 mb/d increase offsetting a roughly equivalent contraction in gasoline. Accordingly, Chinese oil use will barely grow over the forecast period – a far cry from the 2010s, when the country's oil demand grew by 6% annually. Instead, India will lead global gains, rising by 1 mb/d over the forecast. However, India will fall well short of attaining China's spectacular pace of expansion, with its per capita GDP and oil consumption remaining at a fraction of its northern neighbour.

Fundamentals

A new era of protectionism tempers GDP growth

Amid structural headwinds such as ageing populations, increased protectionism and stretched government finances, global GDP growth is projected to average near 3% over 2025-30 – almost half a point lower than during the 2010s. Emerging economies will account for the bulk of this expansion, with average non-OECD growth of 3.9%, compared to 1.8% for OECD countries. By 2030, the non-OECD share of global GDP will climb to 59%, from 56% in 2024.

Well before the United States shifted to strongly protectionist trade policies in early 2025, the past decade had already witnessed a sharp increase in measures hampering trade and investment flows amid a broader process of deglobalisation. The ratio of cross-border trade and investments to GDP has essentially stalled over the past decade amid a global retreat from free trade towards mercantilist policies, tariffs and subsidies. Besides the direct stagflationary impact of higher tariffs and other restrictions to exports and imports, the accompanying uncertainty acts as a deterrent for trade and investment over the forecasting period. A case in point is the Baker, Bloom and Davis Global Economic Policy Uncertainty Index surging to the highest level ever in April 2025.

Before the latest uncertainty surrounding tariffs took the spotlight this year, the global economy had displayed considerable resilience in the wake of the unprecedented central bank interest rate hikes of 2022-23. Post-pandemic demand and supply shocks had propelled inflation in developed economies to 9-10% by mid-2022 – a 40-year high. Inflation has since made a retreat, and most major central banks have now pivoted to an accommodative monetary stance. The main exception in this regard is the United States, where easing has, for now, come to a halt due to inflation proving stickier than initially expected. However, with breakeven inflation rates derived from bond markets pricing annual US inflation in at around 2.4% over a five-year horizon, it is not yet at risk of becoming psychologically entrenched.

Still, a range of structural factors may pressure inflation upward and weigh on growth in the longer term, making for a stagflationary cocktail and conclusively putting an end to the low-interest rate environment that prevailed for most of the past two decades. At the heart of these issues are adverse demographics in developed countries, where an ageing population is set to depress labour productivity, strain fiscal balances and boost public debt – the latter aspect already stretched by ballooning spending for defence, healthcare and social welfare. Spiralling budget deficits and unsustainable fiscal policies are increasingly burdening economic growth, as a greater share of government revenues is allocated to debt refinancing and interest rate payments. In this regard, the International Monetary Fund (IMF) has pointed to the urgent priority of tackling an “unforgiving combination of low growth and high debt” as global public debt reached a record USD 100 trillion in 2024.

In parallel, geopolitical tensions are reshaping trade patterns. Besides conflicts in Europe and the Middle East, China is increasingly the focal point amid accusations of unfair trade practices as the country essentially exports its domestic economic imbalances. Additionally, China’s territorial claims have led to progressively fraught relationships with its neighbours. Trade tensions with the United States have risen in parallel, concentrated in technology and intellectual property.

Real GDP growth assumptions

	2011-2019	2023	2024	2025	2026-30	Vs 2010s
United States	2.4%	2.9%	2.8%	1.2%	2.3%	-0.1%
Europe	1.9%	1.4%	1.7%	1.4%	1.5%	-0.4%
Japan	0.9%	1.5%	0.1%	0.8%	0.2%	-0.6%
China	7.3%	5.4%	5.0%	4.1%	3.8%	-3.5%
India	6.8%	8.9%	6.6%	6.5%	6.4%	-0.4%
Africa	3.6%	2.7%	3.3%	3.7%	3.9%	0.2%
OECD	2.1%	1.8%	1.7%	1.2%	1.9%	-0.2%
Non-OECD	4.7%	4.6%	4.4%	4.0%	3.9%	-0.7%
World	**3.4%**	**3.3%**	**3.2%**	**2.8%**	**3.0%**	**-0.3%**

Source: Oxford Economics.

Assumptions about GDP growth and its impact on oil demand are a key component of our estimates. The average GDP elasticity of global oil demand used for the modelling (before substitution effects) is about 0.3 for OECD and 0.6 for non-OECD, reflecting the greater oil-intensity of emerging markets.

Additionally, expectations of future oil prices are paramount for demand estimates, with forecasts sensitive to both the absolute price level and intertemporal price changes. Estimates are based on the ICE Brent forward price curve (rising from

USD 64/bbl in 2026 to USD 67/bbl in 2030). For 2025, prices are prorated between realised Brent prices and the forward curve. These are then discounted to real terms.

GDP in the **United States** is assumed to grow by an average 2.1% over the forecast period, building on its strong post-Covid recovery. The country continues to outperform other developed economies, with growth and productivity buoyed by a healthy demographic profile, flexible labour market, consumer-led economy, supply-side dynamism and technological innovation. Conversely, unsustainable fiscal spending, surging national debt and uncertainty regarding trade policies act as headwinds. The 2024 budget deficit topped USD 1.8 trillion, or 6.4% of GDP, while publicly held federal debt of USD 28 trillion approaches 100% of GDP. This is expected to keep inflation elevated and monetary policy relatively restrictive, causing GDP growth to decelerate from 2.6% in 2028 towards 2% at the end of the forecast period.

The long-ailing **euro zone** is set to gradually emerge from the stasis that characterised 2023-24 when members' economies barely expanded. Growth will average 1.5% over the forecast period, led by Germany's recovery to its trend rate of around 2%. In this regard, the country's recent commitment to revive its moribund economy through fiscal spending looks to be a game changer. With inflation having recently decelerated towards the European Central Bank's 2% target, accommodative monetary policy will be a key tailwind, boosting real incomes and domestic demand. However, this makes for a still-subdued pace of expansion, about half a point below the 2010s average, as the bloc faces the spectre of so-called 'Japanification'. Amid low productivity and grim demographics, the region's working-age population is about to enter contraction. Growth will be led by the service sector, especially in Southern European economies, where surging tourism is a major source of support. By contrast, industrial production, which has been in decline for more than three years, remains muted – well below pre-Covid levels – amid soft external demand. Protectionist US policies and increased competition from China may crowd out EU countries in global trade as its competitiveness erodes.

Japan's expansion will gradually subside from around 1% mid-decade towards zero at the end of the forecast period, weighed down by chronically low productivity and dire demographics as an ageing population translates into a shrinking labour force.

China's growth will decline steadily over the outlook period as the country faces myriad structural headwinds. GDP expansion will slide to 3.7% in 2030 – half the 2010s pre-pandemic trend. Besides a shrinking population (set to decline by 1.3% between 2025 and 2030), a protracted property slump and massive overcapacity, there is the ever-present risk of a deflationary spiral. China's export-led industrial model in solar panels, automobiles and batteries is increasingly coming under threat, with important trading partners reluctant to absorb the cheap exports with which the country is flooding global markets. As consumer spending remains cautious, authorities have stepped up fiscal and monetary stimulus. However, this will not be sufficient to structurally revive sluggish domestic activity.

India's stellar expansionary trajectory will continue essentially unabated, with GDP growth averaging 6.4% over the forecast period. This is the highest by far of any major economy, propelled by structural advantages such as an expanding middle class with growing spending power and young population dynamics. Additionally, improved infrastructure will help to boost mobility and car ownership. Oil demand will grow at a relatively fast rate as changing spending patterns, urbanisation and industrialisation make India's economy more energy intensive.

Economic and technological shifts slow the rise in per capita fuel use

Perhaps the single most important driver of oil demand is economic growth. While higher GDP typically leads to increased oil consumption, this connection can be uneven and changes over time. The relationship between demand for the three major transport fuels (gasoline, gasoil and jet fuel) and GDP is illustrative in this respect.

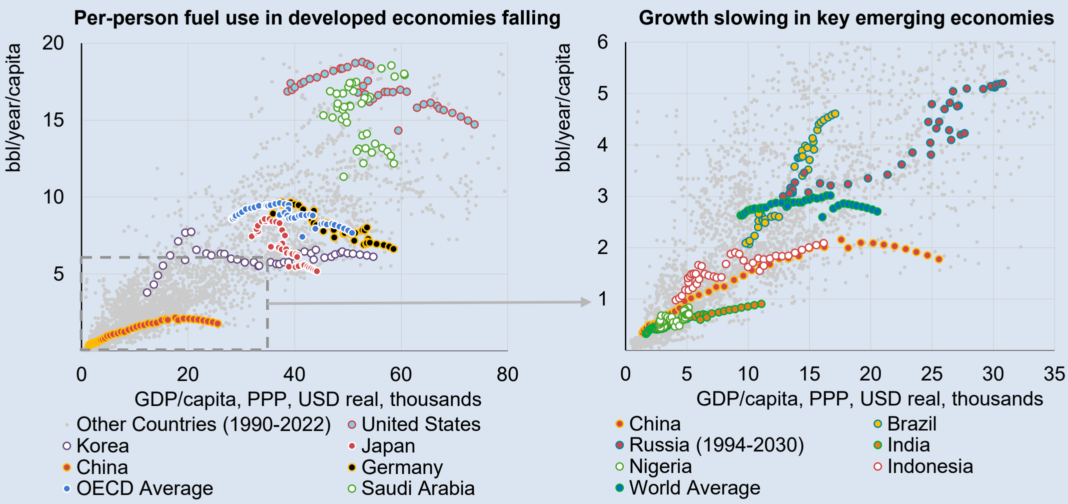
Rising utilisation of fuels produced from oil have historically played a key role as GDP per capita increases. Gasoil use is crucial in expanding the industrial and extractive sectors and the establishment of associated logistic networks involved in an economy moving to middle income status. The fuel is also essential in construction and related fixed capital formation. Gasoline and jet fuel demand goes up significantly as middle class disposable incomes, car ownership and opportunities for leisure travel rise.

Over time, as the service sector begins to comprise a larger piece of the economy, the share of growth in fuel-intensive sectors declines. The amount of personal travel is also fundamentally limited by time and distances so growth in distance driven per person slows at higher incomes.

The United States has comparatively steep fuel use per capita, amongst the highest of all major economies and more than double that of Germany, Japan or the United Kingdom. This results from a combination of several factors. The United States has very high average incomes combined with a low population density and sprawling cities. It also has a comparative lack of well-developed public transport networks. As well, the country's status as a very large oil producer helps to keep consumer prices relatively low while other countries apply substantial fuel taxes.

In these terms, nations like Saudi Arabia, Canada and Australia are more like the United States than other highly industrialised nations in Europe and Asia. Amongst large middle-income economies, it better reflects the direction of travel for Brazil and the Russian Federation (hereafter, "Russia") than densely populated China and India.

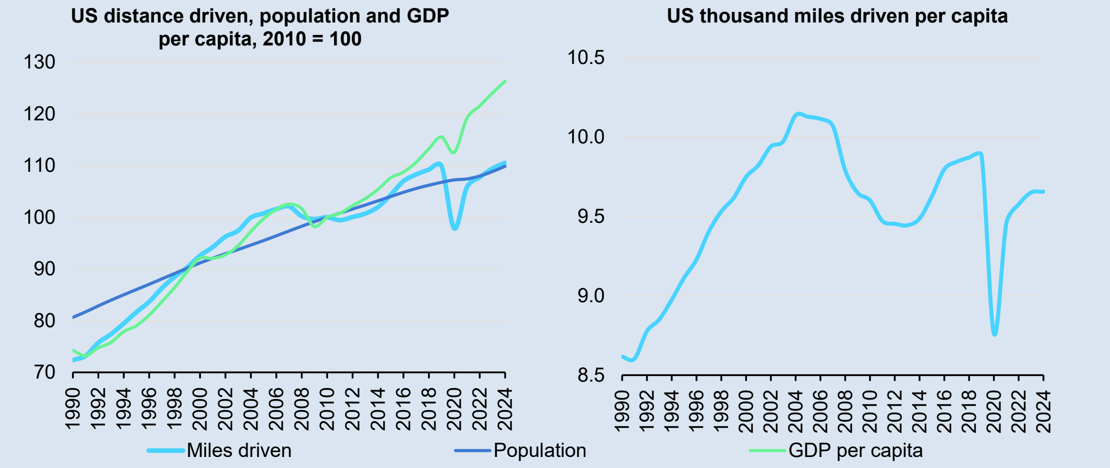
GDP vs. total gasoline, jet/kerosene and gasoil demand per capita, 1990-2030



Note: PPP = Purchasing Power Parity.
Source: IEA analysis based on data from Oxford Economics.

US fuel demand per capita has been steadily declining since the early years of this century. The same is true for the OECD as a group and comes despite widespread GDP growth per head. Some wealthy non-OECD states, notably Saudi Arabia, also display similar trajectories as other sources of energy are increasingly used in power generation and industry, and the role of less oil-intensive sectors rises.

US vehicle miles travelled (VMT), reported by the Federal Highway Administration, are a key indicator for global oil demand, with US drivers accounting for roughly one-third of all gasoline consumed worldwide. Before the Global Financial Crisis (GFC) in 2008, VMT rose steadily in line with rising incomes. Since then, VMT/capita has gone up, albeit unevenly, slightly lagging overall population growth and well below increases in income. Notably, neither the post-GFC nor the post-Covid rebound returned average driving rates to earlier levels. The 2024 VMT/capita was nearly 5% below pre-GFC levels despite an almost 25% real terms increase in GDP per capita. Higher fuel prices, especially in 2007-08 and 2011-14, likely played a role, as has an ageing population and the significantly increased prevalence of teleworking. With US distances driven reaching what appears to be a saturation point, improving fuel economy and EV substitution are gradually eroding demand.

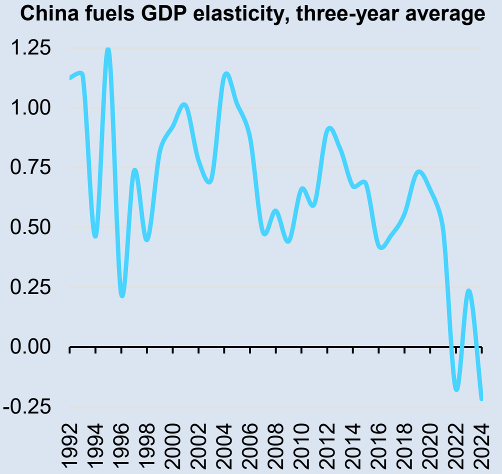


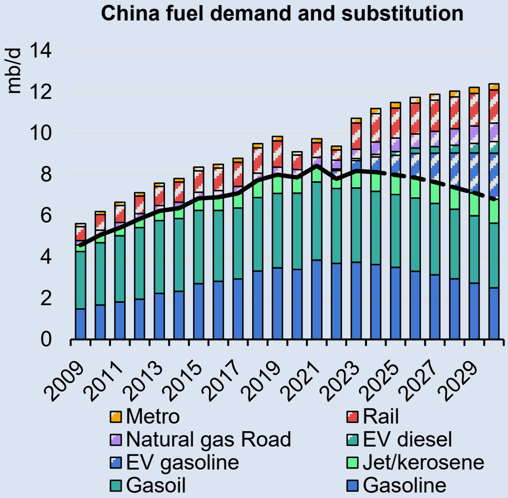
Sources: US Federal Highway Administration and Oxford Economics.

In Japan, a combination of a rapidly ageing population, the end of a construction boom and excellent public transport infrastructure (including a world-class high-speed rail network) means that fuel use per person has fallen by more than 25% since 1990, despite a 30% increase in GDP per head. Very strong car fleet efficiency gains (see *Hybrid-driven vehicle fuel efficiency gains cutting Japanese gasoline use*) have added to this brisk downward trajectory. Many of these factors also apply to Korea, which is even more densely populated than its eastern neighbour. Korean per capita GDP has grown spectacularly since 1990, from a level equivalent to present-day Indonesia, to surpass countries like Japan, the United Kingdom and France, centred on an enormous rise in industrial output. Nevertheless, fuel demand per head has fallen by 20% since peaking in 1996. The experiences of Japan and Korea are invaluable reference points for understanding unfolding developments in China and other emerging and developing Asian economies.

Over recent decades, Chinese economic output per capita has increased with remarkable speed, vaulting the country out of a comparatively low average-income range and firmly into middle-income status. Between 1990 and 2024 China's real GDP per capita (PPP) increased by more than 14 times. No major economy comes close to growth on this scale. For example, Indian GDP per head rose by just under five times and Korea's less than four. Perhaps unsurprisingly, China has been the lynchpin of world fuel demand growth through most of the period, with 5.7 mb/d of demand added this century alone, more than one-third of the global total.

While impressive, this fuel demand growth is on a slightly smaller scale than might be implied by the GDP gains. For most economies, the ratio of fuel to GDP, or GDP elasticity, is around 50% and can be much higher in middle-income countries. In China, this was just below 37% for 1990-2024 on average, falling to zero in recent years amid growing substitution in transport.





Source: IEA analysis including data from Oxford Economics.

Much of China's abrupt slowdown in fuel demand growth is being caused by a combination of changes in the drivers of expansion in the underlying economy, with comparatively high growth for services and a deep slowdown in the diesel-intensive construction sector. Moreover, rapid deployment of transport technologies substituting for oil-based fuels is decisively altering the relationship between economic growth and oil. China leads the world in EV deployment, has dramatically expanded high-speed and urban rail networks and almost one-third of trucks sold in the country last year were fuelled by natural gas. This substitution has enabled China to avoid oil demand growth of around 1.2 mb/d since 2019 and we estimate that it will displace another 2.5 mb/d by 2030.

For the world as a whole, this relative slowdown in OECD and Chinese per capita fuel demand highlights the inexorable shift in the economics of oil demand. Alongside technological developments in transport and changing patterns of behaviour since the pandemic, we expect global per capita fuel use, which has already plateaued, to continue to ease. The rate of growth in overall oil demand will become ever more dependent on a small group of rapidly emerging middle-income economies, population increases in high-consuming regions and petrochemical feedstocks.

Road fuel demand

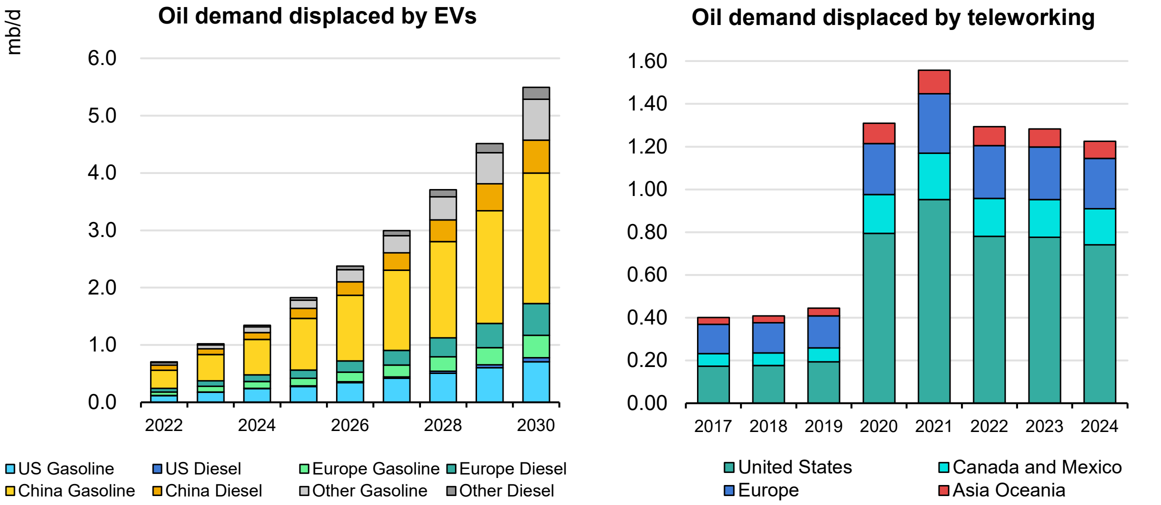
EVs continue to erode gasoline and diesel consumption

Global electric car sales will continue their remarkable growth trajectory, with EVs set to displace a total of 5.4 mb/d of global oil demand by the end of the decade, up from 1.3 mb/d saved in 2024. EV sales exceeded 17 million in 2024, and are expected to surpass 20 million in 2025, representing around one-quarter of all cars sold globally, according to the IEA's Global EV Outlook 2025.

However, these headline numbers disguise significant disparities across regions, with China's buoyancy contrasting markedly with slowing momentum elsewhere. Chinese EV sales were up nearly 40% last year, accounting for almost two-thirds of global sales. Almost half of Chinese cars sold were electric, underpinned by strong government policy support and a wide range of competitively priced models.

Sales elsewhere were less stellar last year, with stagnant growth in Europe and only a modest 10% y-o-y increase in the United States – down from 40% in 2023. In many advanced economies EVs have had trouble extending their appeal beyond urban, environmentally-conscious motorists. High prices in both absolute terms and compared to conventional cars, concerns about the lack of charging infrastructure and driving range, as well as falling second-hand values have kept some buyers on the sidelines. The phasing out or reduction of subsidies in some countries has also added to buyer reluctance. Accordingly, the global EV narrative remains predominantly a Chinese story, with its mass market adoption contrasting with EVs comparative niche status elsewhere.

Oil demand displacement by EVs and by teleworking



By and large, these regional disparities, although becoming slightly less pronounced, will persist over the forecast period, with China's dominance set to continue. In 2030, the global share of electric car sales is set to exceed 40%. EVs will represent 80% of Chinese sales, with the corresponding shares for Europe (60%) and, especially, the United States (20%) more modest. China will account for about half of the projected 5.4 mb/d oil demand savings by 2030, with Europe and the United States each capturing about 14%. About three-quarters of the reductions in demand will be in gasoline, with the remainder in diesel.

Considerable uncertainty surrounds our outlook, not least due to the volatile regulatory landscape. This applies to both domestic markets (e.g. US tax credits could disappear under recently proposed legislation) and internationally. China's dominance of global clean technologies has created frictions with its trading partners, amid accusations that, backed by disproportionate government aid, the country is exporting its structural overcapacity. Additional EU and US tariffs that came into effect last year are a case in point.

Working-from-home jobs transform gasoline demand outlook

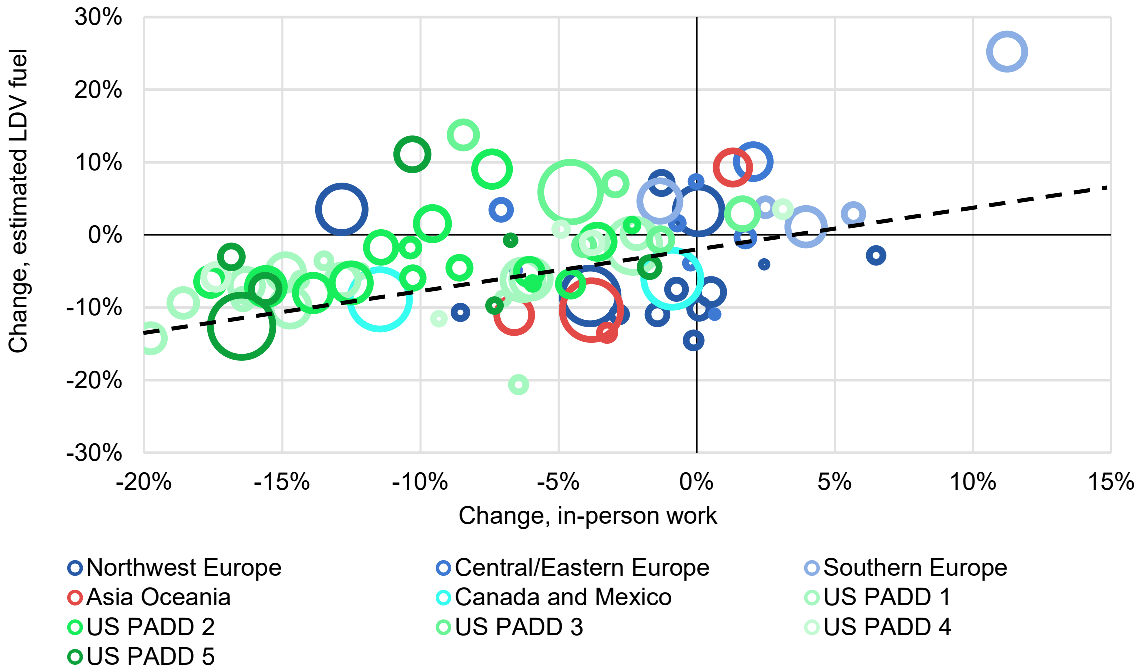
Five years after the Covid-19 pandemic created an acute need for teleworking, working-from-home (WFH) employment has become firmly established in western economies – particularly in the United States. We see the aggregate impact of post-pandemic work-related behavioural changes having reduced global road fuels demand by around 800 kb/d compared to 2019 levels, for a total displacement of around 1.2 mb/d, with this level of savings holding roughly steady through our forecast period to 2030. This reduction is dominated by the United States, where almost 800 kb/d of fuel use is being avoided.

After soaring to 60% at the height of 2020 lockdown restrictions (from below 10% pre-Covid), WFH's share of paid workdays in the United States has remained fairly stable from 2022 onwards, at around 25-30%. US office vacancy rates – currently at a record high of 13.9% and up from 9.3% in 2019 – also reflect this transformation. WFH has proved popular with employees keen to improve their work-life balance by avoiding long commutes. Financial savings for costly travel as well as living in lower-cost areas are other incentives. Amid large differences across age groups, incomes and industries, WFH is more widespread with younger and better-educated urban employees in information technology, finance and the media. This contrasts with sectors such as hospitality and manufacturing where work cannot easily be performed remotely.

Still, hybrid work's ascension to a new normal may be somewhat premature. In 2024, there were numerous reports of large companies reversing their stance on remote and hybrid work, calling corporate staff back to the office five days a week. These employers stepped up their efforts to reclaim control amid worries that remote work weighs on productivity and innovation, with employees disconnected at home seen as less reactive and approachable. This issue remains to be settled, with studies of changes in productivity and teleworking over 2020-23 not showing a significant correlation. Still, the recent cooling of the US labour market, especially in the tech industry, has buttressed employers' bargaining power to roll back remote work.

However, this return to office reversal among large companies does not yet show up in teleworking statistics. The number of US firms requiring five days in the office has actually fallen by six points over 2024, from 38% to 32%, according to data from the research platform Flex Index. Even if 2025 is likely to see tighter policies come into effect, increased teleworking is likely to remain a permanent legacy of the pandemic, with the right to flexible working arrangements now enshrined in law in several European countries. Moreover, ongoing technological advances in videoconferencing may boost WFH further in the longer term.

OECD in-person work and road fuel demand, 2019 vs. 2023



Notes: LDV = light-duty vehicle. PADD = US Petroleum Administration for Defense District. US PADD 1 = East Coast, US PADD 2 = Midwest, US PADD 3 = US Gulf Coast, US PADD 4 = Rocky Mountain and US PADD 5 = West Coast.
Sources: IEA analysis including data from US Census Bureau, US Federal Highway Administration, Eurostat and WFH Research Survey of Working Arrangements and Attitudes.

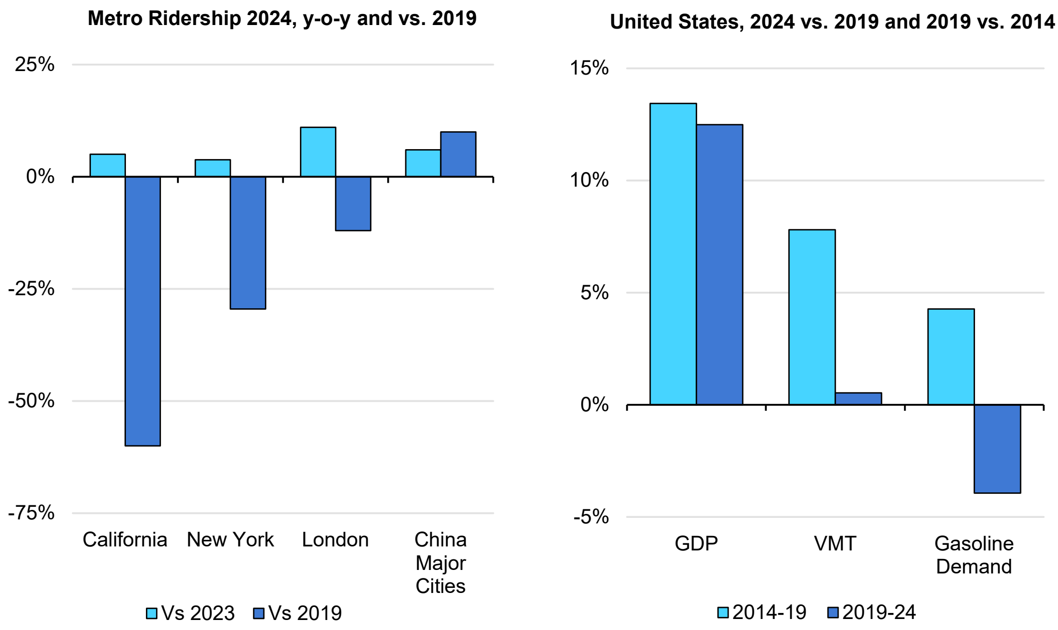
The impact of WFH on gasoline demand has proved most pronounced in the Anglosphere, where it has gained broad cultural acceptance. In fact, cultural individualism emerges as perhaps the main driver for variance in WFH rates across countries, with other factors such as lockdown stringency, population density and GDP per capita also correlating positively to WFH uptake. In early 2025, full-time employees worked from home in excess of 1.5 days per week in the United States, Canada and the United Kingdom, leading other developed economies, according to the Global Survey of Working Arrangements. In Europe, teleworking is most prevalent in northern cities, with London, Stockholm and Amsterdam reporting the highest share of employees working from home in 2023, with more than 50% of residents teleworking either "usually" or "sometimes", according to the EU's Eurostat.

Nonetheless, WFH's link to driving and road fuels demand is not clear-cut. Research shows that, while teleworking reduces both overall distance and vehicle miles travelled in aggregate, teleworkers make more non-commute trips on teleworking days in their freed-up time that offset a significant portion of the reduction in commuter travel. However, these additional trips are typically shorter than commuting and likely more geared towards non-motorised transport modes such as walking and cycling. Daily US travel metric data from the Bureau of Transportation Statistics shows a growing share of trips of less than one mile. These constituted 23.9% of all trips in 2019 and 27.6% in 2023. Along the same line, the average working population staying at home (i.e. not moving more than one mile away from home) has increased by 11% over this period, from 63.4 million to 70.1 million. Additionally, state-level workforce and VMT data reveal substantial variation within the United States, with states in the Northeast and on the West Coast exhibiting higher levels of teleworking and larger declines in driving and implied gasoline consumption.

In the United States, WFH has also accelerated the disconnect between mobility and macroeconomic variables such as GDP and employment trends, with fewer miles being driven per dollar of output. VMT in the United States have lagged GDP for decades, as driving gradually approached saturation – a development subsequently accelerated by teleworking. While cumulative US GDP growth of 13% between 2019 and 2024 is roughly the same as in the five years before the pandemic, mobility growth, weighed down by WFH, has flatlined post-Covid compared to healthy growth in the preceding five years. Gasoline use has fallen even faster than implied by the reduction in VMT, and moved into contraction in the 2020-24 period, with demand 4% below 2019 levels as fuel efficiencies and EVs reduced gasoline consumption per mile travelled. The estimated fuel economy of new US vehicles produced in 2024 increased to an average of 28 miles per gallon (mpg), from 24.9 mpg in 2019, according to the 2024 EPA Automotive Trends Report – despite increasing consumer preferences towards larger, heavier and more powerful vehicles.

Even more than reduced vehicle driving, the increased prevalence of remote working is very apparent in public transport use, with 2024 ridership in major European cities still 5-10% below pre-Covid levels. Declines are even larger in the United States, with subway ridership 30% lower in New York and down 60% on California's Bay Area Rapid Transit system (BART). In cities where public transport competes with commuting by automobile, public transport lost ground to car journeys during the pandemic as health risk-averse travellers switched to driving. This has resulted in a semi-permanent recalibration between modes of transport.

Mobility indicators, pre- and post-pandemic periods



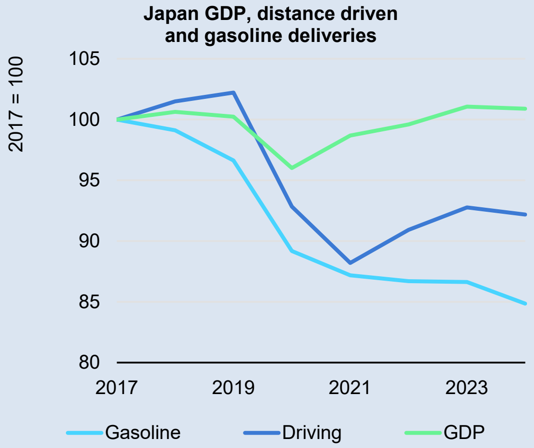
Notes: California = Bay Area Rapid Transit system (BART). VMT = vehicle miles travelled.
Sources: IEA analysis based on data from California's BART system, New York City Transit Authority, Transport for London, China's metroDB.org, Oxford Economics and US Federal Highway Administration.

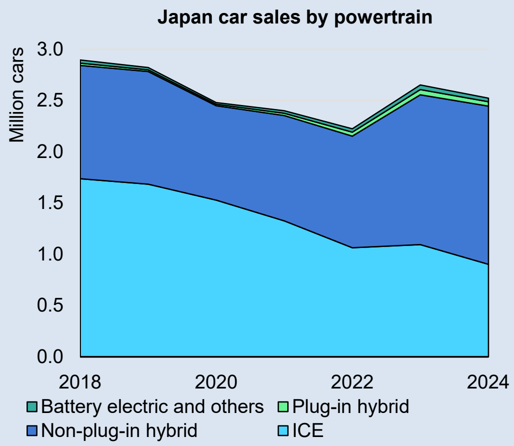
China, where mobility displayed an opposite evolution to western patterns, is the main exception in this regard. This is largely due to WFH being far less prevalent in the country, partly resulting from a very different pattern of lockdowns compared with western economies. Short initial lockdowns were followed by severe restrictions in 2022, culminating in an abrupt release of pent-up mobility after the country's reopening in early 2023. Urban transit use was quick to recover, returning to pre-pandemic levels in 2023 and rising 10% above pre-pandemic levels in 2024. Along the same line, railway passenger volumes were 7.4% above 2019 levels in 2024, according to data from China's National Bureau of Statistics (NBS), while domestic flights have exceeded pre-pandemic levels since early 2023, and in 2025 are up by one-third over 2019 levels. International flights were slower to rebound after the 2023 reopening, rising by around 20% compared to 2019. Holiday travel during China's main festivals averaged 15-20% above pre-pandemic levels between 2023 and early 2025. Conversely, highway passenger numbers in 2024 remained around 10% below 2019, according to the NBS.

Hybrid-driven vehicle fuel efficiency gains cutting Japanese gasoline use

Gasoline demand in Japan has consistently fallen for several years and was almost 15% below pre-pandemic levels in 2024. This decline rate represents a sizeable underperformance compared with GDP, which increased narrowly (+0.6%). While reported distances driven have also significantly decreased, down

9% compared to 2017-19, the faster drop in gasoline deliveries reflects the substantial improvements in the car fleet's fuel economy resulting from extensive hybrid vehicle sales.





Note: ICE = internal combustion engine.
Sources: E-Stat.go.jp, Oxford Economics and Japan Automobile Dealers Association.

Japan has long led the world in the development and deployment of hybrid electric vehicles (HEV). At 61% of total car purchases in 2024, dominated by non-plug-in hybrids, sales were higher than in any other major economy. The result has been efficiency gains of around 1% per year, close to the rate achieved in other OECD countries, but from a more efficient starting point. Conversely, EV sales have been lower than in other developed markets, leaving hybrid engines as the main technological driver of reductions in fuel demand.

The substantial fall in overall driving levels reflects a steady decline in the country's working-age population This demographic limit on underlying mobility is likely to become a more widespread trend as increasing numbers of developed and middle-income countries grapple with similar problems. Teleworking is a much less important drag on mobility in Japan compared with other wealthy countries. Japan's highly urbanised population and excellent public transport networks also help to mitigate the pass-through from economic growth to kilometres driven.

This combination of reduced driving and 1% per year fleet efficiency improvements has led to an average annual decline in gasoline use of around 2% in recent years. Japan's comparatively stable GDP draws these trends into sharper focus, but similar patterns can be seen elsewhere. In the United States, the largest gasoline market in the world, deliveries were well below their 2019 level in 2024, despite increased driving, GDP and employment. Fleet efficiency gains across the OECD are also close to 1% per year, but these owe more to tightening standards for ICE vehicles and more substantial and growing substitution by EVs, while more prevalent teleworking has seen mobility lag other macroeconomic indicators.

Petrochemical demand rising strongly

Feedstocks remain the backbone of global oil demand growth

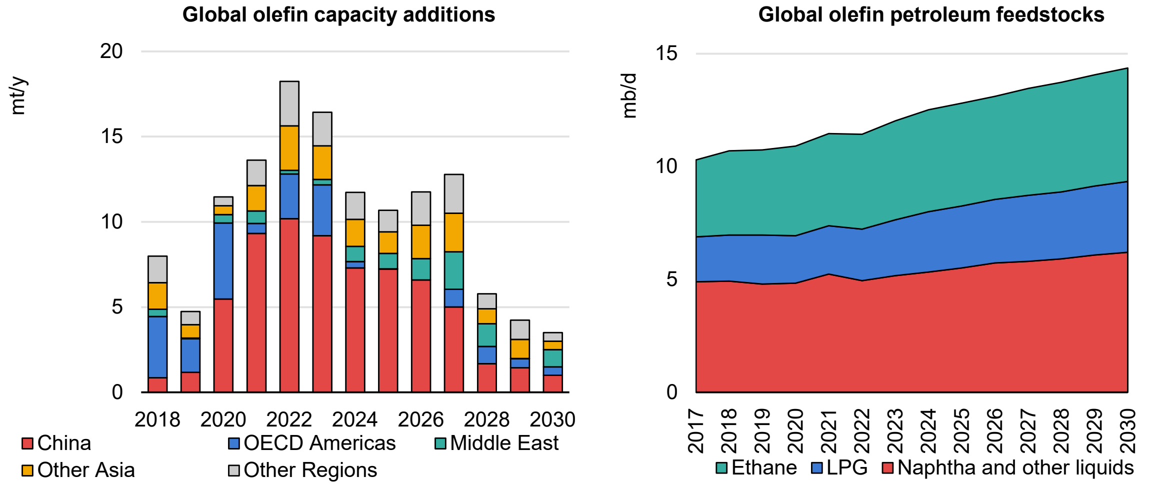
Rising use of oil products as raw materials for the production of plastics and synthetic fibres cemented petrochemical's dominance of overall oil demand growth in 2024, accounting for about three-quarters of net growth. We expect this increase to continue over the remainder of the decade, and beyond, with petrochemical feedstocks' share of total oil consumption rising from 15.8% last year, to 17.4% by 2030. Reaching 18.4 mb/d by the end of the forecast period, feedstock demand will be 2.1 mb/d above 2024 levels – split across naphtha (10.2 mb/d, +1.1 mb/d) and LPG/ethane (8.2 mb/d, +990 kb/d). The rapid increase in LPG and ethane processing, especially in the United States, has been underpinned by burgeoning NGLs supply.

The petrochemical sector was already the overwhelming driver of demand growth during the last five years. Between 2019 and 2024, consumption of oil-based feedstocks rose by an estimated 2.3 mb/d. This is equivalent to more than 95% of the net increase in overall demand and petrochemicals' share of total oil use increased markedly during the pandemic.

Underlying use of plastics and fibres – for sectors like packing, manufactured goods and construction – will continue to rise steadily, especially in emerging market countries. This is driven by trends like urbanisation, increasing average incomes and higher consumer spending. Growth in online delivery services and new manufacturing industries (including clean energy technologies such as EVs and solar photovoltaic panels) also boost feedstock requirements. We estimate an average annual 2024-30 increase of about 2.1% in oil consumed in the petrochemical sector.

The preponderance of petrochemical inputs in total oil demand growth does not result from a profound acceleration in the consumption of polymers. Rather, it reflects steady growth, in contrast to the structural slowdown underway in key transportation sectors. Plastics use is not subject to factors comparable to vehicle efficiency gains or widespread substitution effects on a scale similar to the electrification of transport. A more rapid rise in the amount of recycled material substituting for virgin polymers could begin to dampen the connection between growing demand from key applications – which include packaging, manufactured goods or construction – and final oil demand. However, while plastic waste collection is improving in many countries, we do not expect this to significantly limit oil use during the forecast period.

Olefin production, capacity and feedstocks, 2017-2030



Sources: IEA analysis of data from *S&P Global* and *ICIS*.

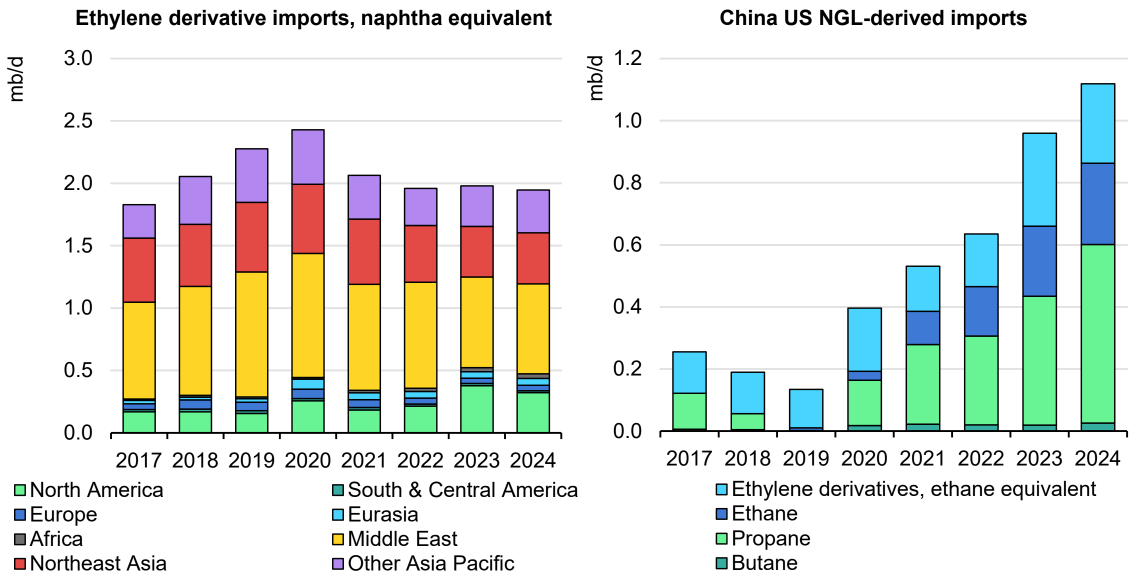
Chinese and US investments bearing fruit

The central role of petrochemicals in oil demand growth is mirrored by the role of China in the sector itself. A major wave of capacity additions, still ongoing, has seen a 2.2 mb/d rise in oil-derived feedstock intake for Chinese plants from 2019 to 2024. This increase, close to the global rise over the same period, saw a 15% (330 kb/d) drop in feedstock-equivalent petrochemical imports, according to data from *ICIS*.

China's new capacity has come in the form of a combination of refinery-integrated naphtha crackers, alongside coastal propane dehydrogenation (PDH) plants and steam crackers based on imported NGL feedstocks. Therefore, the 2019-24 increase in feedstock demand has been split between naphtha (+1.3 mb/d) and LPG/ethane (+890 kb/d). Since naphtha crackers produce about one tonne of propylene for every two tonnes of ethylene and PDH plants produce only propylene, this also means that national petrochemical output of both ethylene (roughly +19 million tonnes per year (Mt/yr), or +110%) and propylene (about +17 Mt/yr, +130%) went up dramatically over the five years to 2024. Other recent waves of capacity additions, for example in the United States and Middle East, have focussed on monetising local ethane supply. Ethane cracking produces very little propylene, offering naphtha crackers some respite when competing in international markets. However, dramatically increased Chinese propylene output has now become a key contributor to reduced output in regions like Europe and the rest of East Asia and enabled the higher run rates at export-focussed US ethane crackers.

In addition to new capacity, patterns of petrochemical demand growth have been shaped by changing feedstock availability. US output of NGLs has risen by more than any other source of supply in recent years and this material has enabled the major increases in US and Chinese petrochemical intake of LPG and ethane. US ethane demand has gone up by 790 kb/d from 2019 to 2024. Much of this production of polymers goes for export, but also meets rising domestic demand and displaces other feedstocks. Polymer and intermediate export shipments rose by 38%, or the equivalent of 350 kb/d of ethane, between 2019 and 2024. Significant volumes flow to Latin America, Europe and various non-OECD Asian markets (including China). Over the same period, US exports of ethane and LPG have gone up by 1.1 mb/d to 2.6 mb/d, with almost three-quarters of this rise directed to China.

Olefin production, capacity and feedstocks, 2017-2030



Sources: IEA analysis of data from *ICIS* and *Kpler*.

In total, including polymer imports, the equivalent of 1.1 mb/d of US NGLs were shipped to feed Chinese demand for plastics and fibre last year. As such, the primary drivers for global supply and demand, respectively, are woven together. While increased trade tensions and tariffs could put this at risk due to the significant China-US petrochemical synergies, our base case is that these trade flows continue mostly intact. European and Indian NGL import volumes have risen in recent years and are set to continue growing through 2030, but only the Chinese petrochemical system has the capacity to process LPG/ethane imports on the scale implied by US exports.

Demand falling elsewhere amid intense competition

The way that Chinese and US producers have expanded market share, via import substitution and exports, respectively, means that the pressure of increasing global overcapacity has largely fallen on other regions. Higher-cost regions, like Europe and East Asia, have been targets for additional flows from traditional exporters. Although some lower-cost producers, including those in the Middle East, have suffered amid more competitive global trade, this trend has disproportionately impacted naphtha crackers. This results in LPG and ethane substituting for naphtha consumption on a global level.

The European petrochemical industry has been perhaps the hardest hit by increased competition, with an estimated 19% fall in total feedstock consumption from 2019 to 2024. Regional industrial demand for plastics softened with import volumes rising simultaneously. While naphtha crackers had relatively limited direct exposure to sharply higher natural gas prices in 2022, production of energy-intensive ethylene derivatives like polyvinyl chloride (PVC) and styrene appears to have been displaced on a larger scale, undermining local olefin demand.

Along with a shift in the average cracker feedstock mix, with operators (especially in coastal locations) using more LPG because of favourable pricing, the fall in operating rates substantially weakened European naphtha demand. Deliveries of the product averaged less than 900 kb/d in 2023, a multi-decade low, before a partial rebound in 2024. We expect further declines (totalling about -10%) over the rest of this decade driven by capacity closures – some already in effect and others announced for 2025 and 2026 – with additional cutbacks likely.

Run cuts or outright closures will be heavily concentrated in high-cost zones like Europe. Smaller declines have been recorded in OECD Asia, despite the latter’s more direct exposure to competition from new plants in China. While Europe and Northeast Asian steam crackers have a similar cost base, many European plants are run by major companies that operate in several parts of the world and aim to optimise output across their global portfolio. Conversely, Japanese and Korean firms tend to be more domestically concentrated.

Korean plants also benefit from being highly integrated with local refineries and downstream demand as well as being larger and more modern, while falls in feedstock use for the generally older, smaller Japanese fleet have been more comparable to their European peers. The resilience of Korean plants, and the start-up of the new Shaheen petrochemical complex will see deliveries edge higher over the remainder of the decade. Korea's Shaheen project, which we assume will begin operations in 2027, is a so-called 'crude oil to chemicals' (CTC) refinery, including a 1.8 Mt/yr mixed-feed steam cracker. The project is being develop by S-Oil, which is 63% owned by Saudi Aramco. As such, it is reflective of an intensification of the long-standing trend for greater downstream integration by major oil producers.

Production in the Middle East appears to have been impacted by global overcapacity, although limited data availability makes the region's petrochemical operations especially opaque. Taking advantage of very low feedstock and energy costs, Middle Eastern steam crackers are generally estimated to be the most cost competitive in the world. Local demand is quite low compared to the feedstock resources available, so plants in the region are overwhelmingly geared to produce commodity polymers for export, especially polyethylene (PE) and polypropylene (PP). China, the world's largest plastics import market, has long been the most important outlet, especially for Saudi Arabian and Iranian production. Both these countries have seen substantial falls in their exports since 2019 (as reported by importing countries). China has become a virtual monopsonist for Iranian petrochemical exports and recent years have seen a fall in the flow between the two countries, although a rise in domestic use may have mitigated some of this decline.

Saudi ethylene derivative exports to the world fell by about 30% between 2019 and 2024 in ethylene equivalent terms, according to *ICIS* data. In part, this may reflect increased domestic consumption, with solid non-oil GDP growth and substantial construction, infrastructure and clean energy investment programmes underway. Nevertheless, we estimate that Saudi feedstock use dropped by about 80 kb/d over the period, concentrated in LPG/ethane, and it is possible that the fall was even larger. It may be that national priorities around the provision of natural gas, especially for power generation (see box, *Saudi plans lead push to slash oil-fired electricity generation*), have seen less ethane extracted from gas streams. Reported Saudi Aramco NGLs data suggest that available ethane volumes may have declined by 70 kb/d, or 18%, between 2019 and 2024. There have been sporadic reports of feedstock shortages at Saudi ethane plants, and it is difficult to reconcile strong estimated cracker margins with a decline in activity.

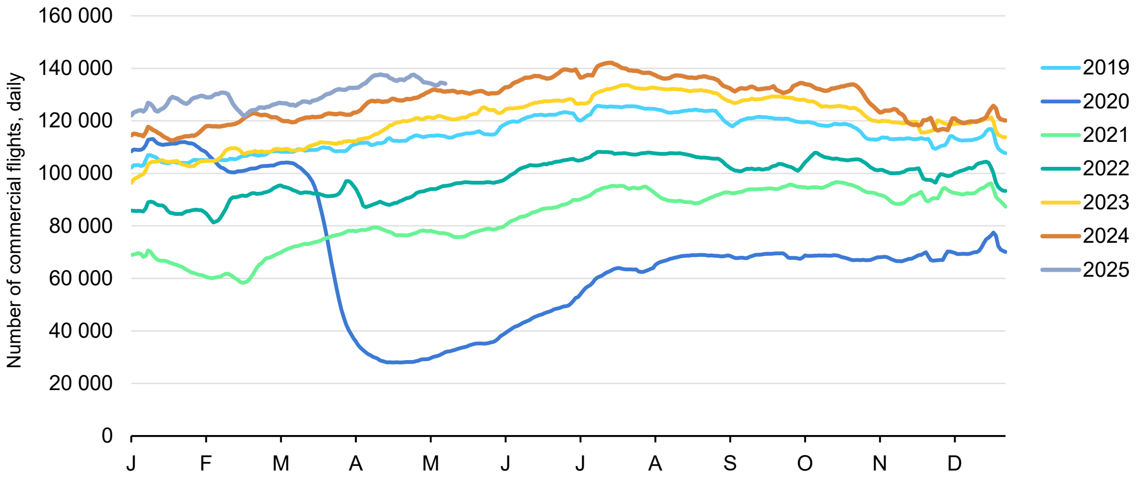
Efficiency gains slow underlying growth in aviation and marine demand

Jet fuel demand on course to regain pre-Covid levels

Amid record-high airline passenger numbers and revenues, the commercial aviation industry has completed its recovery from the pandemic crisis, the worst in its history. On a global level, air travel had already regained pre-pandemic levels in 2023 by metrics such as the number of flights, passengers and miles flown. Domestic travel was the first to complete this rebound, with international travel following in early 2024. On a regional basis, the main exception is Asia Pacific, where international revenue passenger kilometres (RPKs) in 2024 remained 8.7% below 2019, according to data from the International Air Transport Association (IATA). Connectivity for the region took longer to recover as travel restrictions were lifted later than elsewhere. However, Asia Pacific is also set to regain pre-pandemic levels in 2025.

Overall jet/kerosene consumption gains of 130 kb/d in 2025 are only slightly behind the average pace of the 2010s, further suggesting that the post-Covid boom has concluded. Still, jet/kerosene uptake will remain 2% below pre-pandemic levels in 2025 as improved efficiencies counterbalance robust underlying growth in air travel.

Global number of commercial flights (daily), 2019-2025



Source: IEA analysis based on data from *FlightRadar* and *Bloomberg.*

Besides operational efficiencies such as increases in passenger load factors, airplane utilisation and seat density, this is chiefly due to large strides in fuel savings weighing on demand growth. Advanced technologies such as improved aerodynamics, the use of lightweight materials and enhanced engine propulsion all combine to reduce drag and eke out fuel economies. This technological transformation accelerated during the pandemic period after airlines retired a large share of their fleets and replaced them with new narrow-body flagship models such as the Airbus320neo (from 2016) and the Boeing 737 MAX (2017). These are about 20% more fuel-efficient than those they are replacing.

As ongoing fleet renewal combines with technological advances, improvements in fuel burn will slow, but not subvert, jet/kerosene's upward demand trajectory. Besides a decelerating pace in efficiency gains (our models see a gradual easing in the annual rate of efficiency savings over the forecast period, to around 1% by 2030), strong demand for air travel will support moderate growth, with jet/kerosene uptake only reaching pre-pandemic demand levels by 2027. In our outlook, demand is forecast to rise by a cumulative 1 mb/d in 2024-30, and by an average annual growth rate of 2.1%. By growing throughout the forecast period, jet/kerosene's outlook is relatively upbeat, at least when compared to road and marine transport fuels. Assumptions about the global economy are central to our forecast, given jet/kerosene is the most dependent on the macro backdrop among the refined products. The current subpar global economic growth outlook amid uncertainties on trade policies could yet weigh further on demand.

The Asia Pacific region is projected to dominate travel growth. IATA sees an annual expansion of 5.1% in passenger numbers – roughly double the rate of mature markets such as North America's 3.1% and Europe's 2.5%. Besides a fragmented geography suited for air travel, healthy population growth and a growing urban middle class with higher disposable income and wealth are boosting appetite for air travel, perceived as a luxury good. In turn, this reliable customer base supports the case for capacity investment in airports and airplanes.

Subdued trade and IMO efficiencies erode marine fuel demand growth

Demand for marine fuels, which is comprised of maritime bunkers and domestic navigation, is expected to flatline at around 5 mb/d over the forecast period, as subpar underlying growth in shipping combines with rising costs in the wake of the ongoing tightening of marine decarbonisation standards.

Recent years have seen significant disruptions to global maritime traffic, as attacks on vessels in the Red Sea forced some vessel operators to avoid the Suez Canal and seek alternative routes. Additionally, a severe drought at the Panama Canal reduced transits. While longer journeys and faster speeds initially supported bunker sales, international bunkering gains of 140 kb/d in 2024 were only slightly above trend, as soaring freight and insurance rates disincentivised maritime transport. Weak economic growth also acted as a headwind, with Germany's protracted slump weighing on European bunker sales.

The tariff turmoil unfolding in 2025 will make for an even harsher environment for global trade and shipping, with marine fuels disproportionately affected by lacklustre economic expansion. This merely accelerates the ongoing disconnect between GDP growth and maritime trade – the latter has lagged the former for more than a decade – amid a slower pace of globalisation and a GDP-shift from goods to services.

Our models assume an aggregate increase of around 10% in tonne-kilometres (tkm) over the forecast horizon, but this will be counterbalanced by efficiency improvements. Accordingly, we see a flattish demand profile for marine bunkering.

Emission standards mandated by the UN's IMO will continue to tighten. Under IMO 2020 regulations, limits already reduced the sulphur content of fuel oil to 0.5%. This prompted a switch from heavy fuel oil (HFO) to very low sulphur fuel oil (VLSFO) and to marine gasoil (MGO), as well as the installation of exhaust gas cleaning systems, known as 'scrubbers.'

Additionally, the Mediterranean became a Sulphur Emission Control Area (ECAMED) in May 2025, cutting fuel sulphur limits to 0.10% – matching the stricter standards seen in Northern Europe and North America. In parallel, under IMO regulations approved in April 2025, standards are set to become even more restrictive towards the end of the decade with the introduction of a global greenhouse gas (GHG) pricing system. Merchant ships will have to pay a penalty for above-target GHG emissions starting in 2028, encouraging use of lower emission fuels like biofuels, ammonia and hydrogen.

Demand developments by region

North American, European oil demand declines by 1.3 mb/d

North American oil demand will end the decade at 24 mb/d, after plateauing at around 24.6 mb/d in 2025. The region's consumption will fall by an average 0.4%, or 570 kb/d, over the forecast period. The **United States**, representing around 80% of North American oil consumption, will account for the bulk of the decline, with smaller contractions in **Canada** and **Mexico**. Although US oil demand has hovered around 2019's level in recent years, the region's overall consumption is not expected to regain its pre-pandemic high-water mark. Gasoline will be the main drag on use, declining by 790 kb/d between 2024 and 2030, with its outlook undermined by an expanding EV fleet, burgeoning vehicle efficiencies and the assumed absence of a decline in WFH employment. Still, this marks a much smaller contraction than *Oil 2024's* expected decline of 1.6 mb/d due to lower assumptions about EV penetration. Electric vehicles are expected to account for 20% of US total car sales in 2030, down from 55% assumed last year. Amid stagnation or declines elsewhere in the product spectrum, the only ones posting steady growth in our 2024-30 forecast are jet/kerosene and LPG/ethane, for aggregate increases of 180 kb/d and 370 kb/d, respectively. For LPG/ethane, the average growth rate of 1.7% stands in marked contrast to its 4% annual increase between 2019 and 2024. This slowdown is mainly due to the lack of further substantial petrochemical capacity expansions that characterised the early 2020s.

North America oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	3.5	3.6	3.8	3.9	4.1	4.2	4.4	4.4	4.5	4.5	4.6	4.6	1.4%	0.4
Naphtha	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5%	0.0
Gasoline	11.0	9.4	10.2	10.4	10.5	10.5	10.4	10.4	10.2	10.0	9.8	9.5	-1.6%	-0.9
Jet/Kerosene	2.0	1.2	1.5	1.8	1.9	2.0	2.0	2.0	2.1	2.1	2.1	2.2	1.7%	0.2
Gasoil/Diesel	5.1	4.6	4.9	5.1	5.0	4.9	4.9	4.9	4.9	4.8	4.8	4.8	-0.6%	-0.2
Residual fuel oil	0.5	0.5	0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-0.2%	0.0
Other products	2.5	2.3	2.4	2.4	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	-0.3%	0.0
Total products	**24.9**	**21.9**	**23.7**	**24.3**	**24.6**	**24.5**	**24.6**	**24.5**	**24.4**	**24.3**	**24.1**	**24.0**	**-0.4%**	**-0.6**
Annual change	**-0.2**	**-3.1**	**1.8**	**0.7**	**0.3**	**0.0**	**0.0**	**0.0**	**-0.1**	**-0.1**	**-0.2**	**-0.2**		

European oil demand peaked in 2022 and will contract throughout the forecast by an aggregate 730 kb/d, or about an annual average decrease of 120 kb/d over the period. The industry-linked fuels naphtha and gasoil will show the fastest rate of declines, each down around 2% annually, in the wake of subpar GDP growth of 1.5% over the forecast period. The switching away from diesel to gasoline-engine cars acts as an additional headwind to gasoil use. In parallel, gasoline demand will post only a marginal decline (-50 kb/d by 2030) as a result of this substitution. Both powertrains have falling market shares, as reported by the European Automobile Manufacturers' Association. The combined share of new gasoline (33.0%) and diesel (10.4%) cars constituted less than half of sales in the passenger market in 2024, while simple hybrid cars accounted for another 31.4%. The only products materially defying the overall slump are jet/kerosene (+1.2% annually) and LPG/ethane (+0.8%), with the latter supported by the start-up of a new ethane-based cracker in Belgium, expected by late 2026.

Europe oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	1.3	1.2	1.2	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	0.8%	0.1
Naphtha	1.1	1.1	1.1	1.0	0.9	1.0	1.0	0.9	0.9	0.9	0.9	0.9	-1.6%	-0.1
Gasoline	2.3	2.0	2.2	2.3	2.4	2.5	2.6	2.6	2.6	2.6	2.5	2.4	-0.3%	0.0
Jet/Kerosene	1.6	0.8	0.9	1.4	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.2%	0.1
Gasoil/Diesel	7.1	6.5	6.9	6.9	6.6	6.5	6.4	6.3	6.1	6.0	5.9	5.8	-2.0%	-0.7
Residual fuel oil	1.0	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	-0.8%	0.0
Other products	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	-0.1%	0.0
Total products	**15.8**	**13.7**	**14.4**	**14.9**	**14.8**	**14.9**	**14.9**	**14.8**	**14.6**	**14.5**	**14.3**	**14.1**	**-0.8%**	**-0.7**
Annual change	**0.0**	**-2.0**	**0.7**	**0.4**	**-0.1**	**0.1**	**0.0**	**-0.1**	**-0.2**	**-0.2**	**-0.1**	**-0.2**		

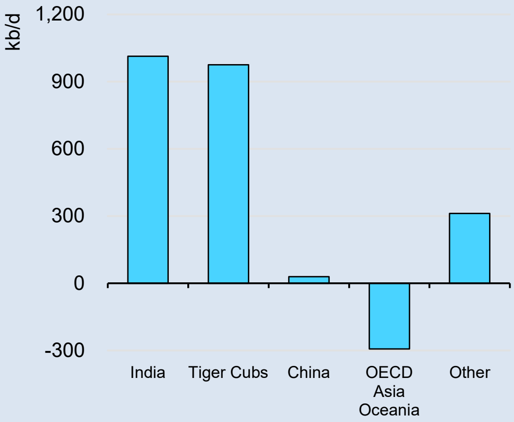
Small group of Asian countries propels global demand growth

Oil demand in the **Asia Pacific** will increase by 2 mb/d, to 40.7 mb/d, over the forecast period, against a backdrop of robust GDP growth of 4% on average for the region. With Chinese consumption flatlining and OECD Asia Oceania contracting by 290 kb/d (weighed down by Japan's drop of 260 kb/d), India will account for around half of this rise at 1 mb/d. A group of five Southeast Asian economies will contribute a comparable amount.

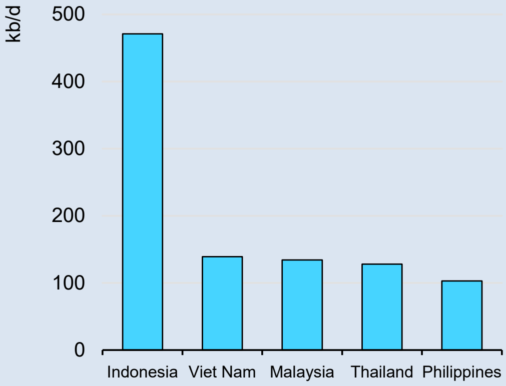
Tiger Cubs roar, driving Southeast Asian oil demand higher

A small cluster of countries – Indonesia, Viet Nam, Malaysia, Thailand and the Philippines – will account for an increasing share of global oil demand growth, rising by a combined 980 kb/d to 6.3 mb/d by 2030. These gains, both in absolute and in relative terms, are led by Indonesia**.** The country's oil consumption is set to grow by 3.8% annually, for a cumulative 470 kb/d in 2030 – the second highest globally after India. The other four countries will see aggregate increases of around 100-150 kb/d each.

Asia Pacific oil demand outlook, 2024-2030



Tiger Cubs oil demand outlook, 2024-2030



This group of five is sometimes referred to as the Tiger Cubs, after the original four Asian Tigers (Hong Kong, Singapore, Korea and Chinese Taipei) that posted exceptional economic growth in the second half of the 20th century. Their export-driven economic models, characterised by technological investments and industrial development, are currently being emulated by the Cubs. Youthful demographics and large domestic consumer markets (of around 600 million people in total, of which 280 million are in Indonesia, the world's fourth most populous country) are other advantages, making for an above-par economic outlook. Our models assume a 5% average annual GDP expansion for the group over the forecast period, by and large continuing the 2010s pre-pandemic trend.

Moreover, the group's oil demand will grow at a relatively fast rate as the energy intensity of their economies accelerates from the low base that is typical for emerging countries. This pertains especially to the Philippines and Viet Nam, categorised as lower middle-income countries by the World Bank, with Indonesia, Thailand and Malaysia classified as higher middle-income.

Collectively, jet/kerosene (+3.2% annually, +80 kb/d in total) and gasoil (+2.5%, +310 kb/d) will propel the group's overall fuel consumption growth – the former buoyed by an emerging middle class eager to travel, the latter by a process of rapid industrialisation. This is in part due to the Cubs' emergence as Asia's key nearshoring hubs. Attracted by low labour costs and relative political stability, companies have increasingly been migrating their manufacturing and supply chains to the region, often by diversifying away from China. To supply this expanding industrial base and rising demand for packaging and construction, the outlook period will see a handful of steam crackers coming online. Naphtha use will rise by 11.4% annually for a total increase of 290 kb/d, led by Indonesia (+170 kb/d) and Viet Nam (+70 kb/d).

Asia Pacific oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	4.4	4.4	4.6	4.9	5.2	5.5	5.6	5.7	5.9	6.0	6.1	6.2	2.0%	0.7
Naphtha	4.6	4.5	4.8	4.8	5.2	5.2	5.4	5.7	5.8	6.0	6.1	6.3	3.0%	1.0
Gasoline	7.6	7.3	7.8	7.9	8.1	8.0	7.9	7.8	7.7	7.6	7.4	7.2	-1.7%	-0.8
Jet/Kerosene	2.9	1.9	1.9	1.8	2.5	2.7	2.8	2.8	2.9	3.0	3.1	3.2	2.6%	0.5
Gasoil/Diesel	9.6	9.3	9.6	9.6	9.7	9.7	9.8	9.9	10.0	10.1	10.1	10.1	0.7%	0.4
Residual fuel oil	2.4	2.4	2.6	2.6	2.7	2.7	2.6	2.7	2.6	2.6	2.6	2.6	-0.4%	-0.1
Other products	4.5	4.5	4.5	4.7	4.7	4.7	4.7	4.8	4.8	4.9	5.0	5.0	1.0%	0.3
Total products	**36.0**	**34.2**	**35.6**	**36.3**	**38.0**	**38.6**	**38.9**	**39.4**	**39.8**	**40.1**	**40.4**	**40.7**	**0.9%**	**2.0**
Annual change	**0.6**	**-1.8**	**1.4**	**0.7**	**1.6**	**0.7**	**0.3**	**0.5**	**0.4**	**0.3**	**0.3**	**0.2**		

Chinese oil demand plateauing

China's oil use will hover around 16.8 mb/d throughout the forecast period, increasing by an almost negligible 30 kb/d between 2024 and 2030 – a sea change compared to the preceding decade when the country accounted for 60% of the global rise in oil demand. The barely positive growth rate pales in comparison to the 6% annual pace during 2010-19. However, the flattish headline numbers mask a sharp divergence among the different product segments, as a contraction in road fuels contrasts with robust growth in petrochemical feedstocks.

The slowdown in oil consumption is particularly unusual considering China's status as a middle-income country, with considerable growth in income and prosperity (our models assume average GDP expansion of 3.9% compared with 7.3% in the 2010s). This decoupling between oil use and GDP occurs due to substitution away from oil in transport amid mass market electrification, which is far more advanced in China than elsewhere. Rapid EV penetration has already caused gasoline demand to peak in 2021, at 3.8 mb/d. An annual consumption decline of a massive 6% will leave the fuel ending the decade at 2.5 mb/d – compared to 3 mb/d assumed under Oil 2024. Gasoil, which peaked in 2021, will see a similar, if less pronounced pattern, with an average annual decline of 2.1% as expanding sales of trucks powered by liquified natural gas (LNG) combine with anaemic construction activity and sluggish consumer spending. Here too, 2030 demand of 3.1 mb/d is well below last year's expected of 3.8 mb/d. Conversely, jet/kerosene will rise by a robust 3.9% on average. This growth is largely due to international air traffic, with increases in domestic flights undermined by the rapid expansion of China's high-speed rail network. Already the largest in the world, it will expand further by 20% to 60 000 km between 2025 and 2030.

The deepening slump in road fuels will leave petrochemical feedstocks as the chief catalyst of China's oil demand growth, with LPG/ethane and naphtha rising by an annual 2.5% and 4.6%, respectively. This will result in a total increase in feedstock demand of 1.1 mb/d between 2024 and 2030 – equal to the decline in gasoline use. China's unprecedented wave of petrochemical additions is set to continue, albeit at a gradually slower pace as the decade progresses.

China oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	1.8	1.8	1.9	2.2	2.5	2.6	2.7	2.7	2.9	2.9	3.0	3.1	2.5%	0.4
Naphtha	1.4	1.5	1.6	1.8	2.3	2.3	2.5	2.7	2.8	2.9	3.0	3.0	4.6%	0.7
Gasoline	3.5	3.4	3.8	3.7	3.7	3.6	3.5	3.3	3.1	2.9	2.7	2.5	-6.0%	-1.1
Jet/Kerosene	0.9	0.8	0.8	0.5	0.8	0.9	1.0	1.0	1.0	1.1	1.1	1.2	3.9%	0.2
Gasoil/Diesel	3.6	3.7	3.8	3.6	3.6	3.6	3.5	3.5	3.5	3.4	3.3	3.1	-2.1%	-0.4
Residual fuel oil	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.2%	0.0
Other products	2.6	2.7	2.7	2.8	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.2	1.0%	0.2
Total products	**14.2**	**14.3**	**15.2**	**15.2**	**16.5**	**16.6**	**16.7**	**16.9**	**16.9**	**16.9**	**16.8**	**16.7**	**0.0%**	**0.0**
Annual change	**0.7**	**0.2**	**0.8**	**0.0**	**1.3**	**0.2**	**0.1**	**0.2**	**0.1**	**-0.1**	**-0.1**	**-0.2**		

India leads global demand growth by a large margin

India's oil demand will increase by a steep 1 mb/d over the forecast period – more than any other country – in the wake of stellar GDP expansion, at an average annual rate of 2.8%. India will remain the world's fastest growing major economy in 2025 for a fourth year running and is projected to overtake Japan as the world's fourth largest economy this year.

Moreover, while all key products will contribute to the expansion, transport fuels will lead the gains – a global anomaly. In relative terms, jet/kerosene will rise the fastest, at almost 6% annually. The fuel, starting from a low base, stands to benefit the most from population growth of 5% between 2025 and 2030 and its rapidly expanding middle class keen to spend on luxury goods and services, including foreign travel. A similar dynamic propels annual gasoline demand growth of 4%, which has significant scope for expansion given low levels of car ownership. Our models assume a 40% increase in the size of the car fleet by 2030 – a rate of expansion that comfortably outstrips the impact of efficiencies and EVs, with growth in the latter category mainly in two- and three-wheelers. A risk to our outlook is that the consumption boom driving demand for India's transport fuels is to a large extent debt fuelled. Borrowing has become increasingly commonplace among India's middle class. Household debt rose to 43% of GDP in 2024, up from 35% in 2022, and a possible credit spiral could derail expansion.

Demand for industrial-linked products will only marginally lag the growth rate for retail-oriented transport fuels, with annual increases in gasoil, naphtha and

LPG/ethane of 3.3%, 2.0% and 2.5%, respectively. For gasoil, making up around one-third of India's total oil use, this amounts to an aggregate gain of 380 kb/d over the forecast period, buoyed by secular trends such as urbanisation, industrialisation and the building out of the country's infrastructure. Expansion in the petrochemical feedstocks tracks the launch of new projects coming on stream, with the widespread adoption of clean cooking acting as an additional boost to LPG demand. Government subsidy programmes have been instrumental in this respect, in particular the Pradhan Mantri Ujjwala Yojana scheme launched in 2016 that aims to provide LPG connections across the country, replacing traditional cooking methods.

India oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	0.8	0.9	0.9	0.9	0.9	1.0	1.1	1.1	1.1	1.1	1.1	1.2	2.5%	0.2
Naphtha	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.0%	0.0
Gasoline	0.7	0.7	0.8	0.9	1.0	1.0	1.1	1.1	1.2	1.2	1.3	1.3	4.0%	0.3
Jet/Kerosene	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	5.6%	0.1
Gasoil/Diesel	1.6	1.5	1.5	1.7	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.2	3.3%	0.4
Residual fuel oil	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7%	0.0
Other products	1.1	1.0	1.0	1.2	1.2	1.2	1.1	1.1	1.2	1.2	1.2	1.2	1.0%	0.1
Total products	**5.0**	**4.6**	**4.8**	**5.3**	**5.4**	**5.6**	**5.8**	**5.9**	**6.1**	**6.2**	**6.5**	**6.7**	**2.8%**	**1.0**
Annual change	**0.0**	**-0.3**	**0.2**	**0.5**	**0.1**	**0.2**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**		

African oil demand to post robust growth

African demand will increase by a solid 2.9% annually over the forecast period – a comparable pace to the continent's population growth (by 15% in total, to reach 1.32 billion in 2030). GDP expansion is equally firm, set to average a higher 3.8% annually over 2024-30, from 3.6% during the 2010s. This consumption increase will be relatively balanced across the product spectrum, with gasoline, gasoil and jet/kerosene all growing by around 2.8% annually. Still, in absolute terms, the role of the latter fuel will remain relatively marginal, at 270 kb/d on average, as air travel remains beyond reach for the great majority of the population. The jet/kerosene pace of expansion pales in comparison to LPG/ethane's 5.1% growth rate, with consumption approaching 900 kb/d in 2030, propelled by soaring use in clean cooking.

Among countries, Egypt will end the decade at 1.2 mb/d in 2030, accounting for more than 20% of the continent's overall consumption. Other leading countries are Algeria, Nigeria and South Africa, each representing around 600 kb/d in 2030. However, the relative fragility of the continent's demand forecast bears emphasising, with Egypt and Nigeria experiencing severe sovereign debt and currency crises as recently as last year, leading to IMF/World Bank bailouts. Still, with its finances now on surer footing, Nigeria's cumulative consumption growth of 26% over the forecast period will be the highest of any major African country, benefitting from a low per capita base in energy consumption, with industrialisation and young population dynamics further propelling growth. This contrasts with South Africa, where oil demand will grow only marginally over the forecast period. Besides a higher baseline, the country's underperformance is set to continue, its protracted power grid crisis reflective of its chronic economic malaise.

Africa oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.9	5.1%	0.2
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6%	0.0
Gasoline	1.2	1.2	1.3	1.3	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	2.6%	0.2
Jet/Kerosene	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	2.8%	0.0
Gasoil/Diesel	1.7	1.5	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.8%	0.3
Residual fuel oil	0.3	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	1.1%	0.0
Other products	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	2.4%	0.0
Total products	**4.2**	**3.9**	**4.4**	**4.5**	**4.6**	**4.6**	**4.8**	**4.9**	**5.0**	**5.2**	**5.3**	**5.4**	**2.9%**	**0.9**
Annual change	**0.0**	**-0.3**	**0.5**	**0.1**	**0.1**	**0.0**	**0.2**	**0.1**	**0.2**	**0.1**	**0.1**	**0.1**		

Central and South American oil demand will grow by an average 1.4% over the forecast period – a relatively subdued rate by emerging market standards. This is in line with equally muted average GDP growth of 2.4%, compared to 3.9% for the non-OECD as a whole. To a large extent, this reflects the continent's structural problems: institutional and legal framework weaknesses, poor labour productivity and an underdeveloped manufacturing base amid heavy reliance on agriculture and mining.

Central and South America oil demand by product, 2019-2030 (mb/d)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8%	0.0
Naphtha	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.8%	0.0
Gasoline	2.0	1.7	1.9	2.0	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	1.6%	0.2
Jet/Kerosene	0.3	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	2.7%	0.1
Gasoil/Diesel	2.3	2.1	2.3	2.4	2.4	2.4	2.5	2.5	2.6	2.6	2.6	2.7	1.5%	0.2
Residual fuel oil	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6%	0.0
Other products	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	1.2%	0.0
Total products	**6.7**	**5.7**	**6.3**	**6.6**	**6.7**	**6.8**	**6.9**	**7.0**	**7.1**	**7.2**	**7.4**	**7.4**	**1.4%**	**0.6**
Annual change	**0.0**	**-1.0**	**0.6**	**0.3**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**		

Brazil, responsible for about half of the region's total oil demand, is a case in point in this respect. Overall oil consumption will increase by around 1.3% annually between 2024 and 2030, with gasoil (responsible for more than a third of Brazil's total demand) expanding at a similarly pace. Farming, dependent on diesel-intensive machinery during harvest and planting seasons, accounts for around one-seventh of this growth. An agribusiness powerhouse, this also represents a vulnerability of Brazil's economy, with agricultural exports complemented by a lack of competitiveness elsewhere.

Argentina, which saw oil demand contract each year between 2014-24, with the exception of the 2020-22 Covid years, will see consistently positive growth of around 10 kb/d per year over the 2025-30 forecasting period. This is in line with solidly positive GDP growth of 3% on average, reflecting the country's resurgent economic outlook in the wake of the Milei Administration's economic reforms.

Eurasian oil demand is set to increase by 300 kb/d over the forecast period, concluding the decade at 4.6 mb/d. Russia, which represents about 80% of the region's consumption, will see growth of only 110 kb/d over the 2024-30 outlook, concentrated in petrochemical feedstocks. Conversely, aggregate demand for gasoil, gasoline and jet/kerosene will be essentially flat amid muted average GDP growth of 0.6% per year.

Middle Eastern oil consumption will fall marginally, by 50 kb/d to 9.2 mb/d over the 2024-30 outlook period. Total demand is forecast to peak at 9.6 mb/d in 2027, after which a rapid decline sets in, exclusively due to an accelerated drop in oil use for power generation. This exceptional decline masks relatively healthy oil demand gains of around 2-3% in the other main fuels, buttressed by GDP growth of about 3.5% and an increase of 1.5% in the region's population. LPG/ethane leads gains at 410 kb/d, followed by gasoline at 280 kb/d while jet fuel/kerosene and naphtha are each up 120 kb/d. This combined growth of 890 kb/d is nevertheless outweighed by plummeting oil use for power generation of a projected 1.1 mb/d, with aggregate declines of 400 kb/d for fuel oil and 540 kb/d for 'other products', dominated by direct crude burning. These massive contractions are largely concentrated in Saudi Arabia, in line with the country's stated policy to phase out oil use for electricity and desalination plants with the substitution of natural gas and renewables (see Box below, Saudi plans lead push to slash oil-fired electricity generation.) Saudi Arabia's oil consumption, which accounts for about 40% of the region's demand, is forecast to decline by 620 kb/d over the forecast period – the most of any country. Iraq is the only other Middle Eastern country posting a drop in oil demand, by 50 kb/d, also due to lower oil burn for power generation. This contrasts with other major economies in the region seeing steady growth, with Iran, Qatar and the UAE expanding by around 150 kb/d each.

Middle East oil demand by product, 2019-2030 (mb/d)

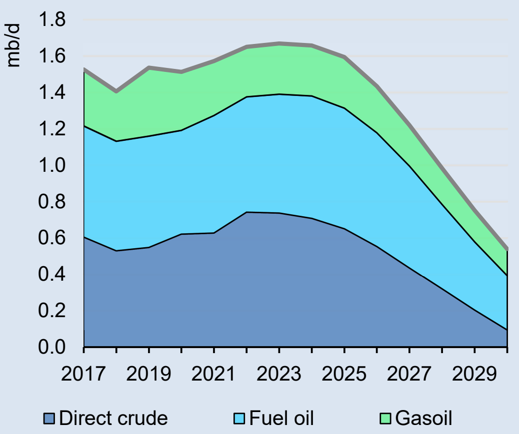
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2024-30 Growth Rate	2024-30 Growth
LPG/Ethane	2.1	2.0	2.0	2.0	1.9	1.9	2.0	2.0	2.1	2.2	2.3	2.3	3.3%	0.4
Naphtha	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	4.2%	0.1
Gasoline	1.8	1.5	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.4%	0.3
Jet/Kerosene	0.5	0.3	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	3.4%	0.1
Gasoil/Diesel	1.8	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.7	1.7	1.7	1.7	-0.4%	0.0
Residual fuel oil	1.4	1.3	1.4	1.5	1.5	1.6	1.6	1.6	1.5	1.4	1.3	1.2	-4.6%	-0.4
Other products	1.1	1.2	1.1	1.3	1.3	1.2	1.2	1.2	1.1	1.0	0.9	0.7	-9.3%	-0.5
Total products	**8.9**	**8.3**	**8.6**	**9.1**	**9.2**	**9.2**	**9.4**	**9.5**	**9.6**	**9.6**	**9.4**	**9.2**	**-0.1%**	**0.0**
Annual change	**0.2**	**-0.7**	**0.4**	**0.4**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**-0.1**	**-0.2**	**-0.2**		

Saudi plans lead push to slash oil-fired electricity generation

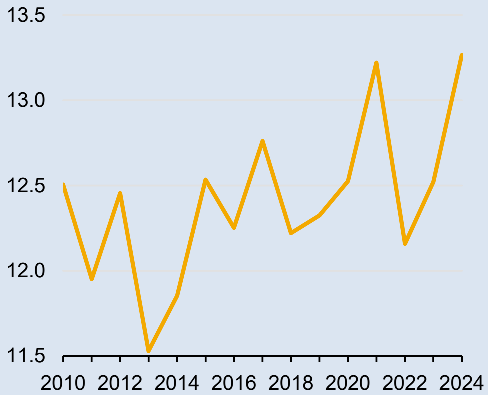
The Middle East is the primary region for oil-fired electricity generation globally but concerted efforts in recent years to ramp up new natural gas supplies will sharply lower oil burning in power plants during our forecast period. Crude, fuel oil and gasoil use in power generation is forecast to plunge by two-thirds before the end of the decade. Oil use for power in the Middle East was estimated at almost 1.7 mb/d in 2024, including 670 kb/d of fuel oil, 710 kb/d of crude and 280 kb/d of gasoil. Based on the delivery of announced plans, we estimate that this will fall by a steep 1.1 mb/d to just 540 kb/d by 2030 as more gas developments, as well as renewable projects, come online. Saudi Arabia, the world's largest consumer of oil for power generation, will account for around 1 mb/d of this decline.

Liquid fuels play an important role in a number of Middle Eastern countries, notably in Saudi Arabia, Iraq, Kuwait and Iran, and are essential for managing peaks in power consumption, as well as meeting base load in areas with lower gas availability. A push to make better use of underutilised gas resources and develop renewable generation is set to reduce this dependence in the region's two largest users of oil in power generation, Saudi Arabia and Iraq. This would come with air-quality and economic benefits, and freeing additional oil for export.

Middle East oil use in power generation, 2017-2030



Saudi Arabia summer CDDs, 2010-2024



Source: IEA analysis including *Bloomberg* data.

The most ambitious plans come from Saudi Arabia which is significantly investing in gas and renewables to meet rising electricity demand and targeting the phase out oil burn in power plants. The Kingdom's Liquid Displacement Programme aims to replace roughly 1 mb/d of oil consumed in power generation, desalination plants and agriculture by 2030 with natural gas, renewables and electrification. Progress thus far has seen several new gas plants already operational or under development and the first signs of this push bearing fruit can be seen in latest data. Saudi use of direct crude and fuel oil was essentially flat from 2023 to 2024, despite a 6% increase in cooling degree days (CDDs) amid extremely hot summer weather. Nevertheless, these strategic investments will likely have their biggest impact on oil demand in the final years of this decade.

The Iraqi power system has come under strain in recent years, with imports of electricity and gas from neighbouring countries insufficient to reduce the need to burn large volumes of crude and fuel oil. The country aims to alleviate these issues by better use of existing gas resources and investments in solar generation. The Gas Growth Integrated Project (GGIP), in partnership with TotalEnergies, will recover gas from the Ratawi oil field, which is currently being flared. Projects like this are forecast to cut Iraqi oil use by about 100 kb/d between 2024 and 2030.

Electricity demand and, by extension, oil-fired power generation was boosted by extremely hot summer temperatures during 2024. Air conditioning is a major contributor to spikes in power use and therefore periods of intense heat and increased CDDs are often associated with sharply higher oil consumption. These extreme weather patterns had a major impact on regional and global patterns of demand in 2024 and variation in temperatures will likely continue to result in uneven Middle Eastern demand over the medium term.

Supply

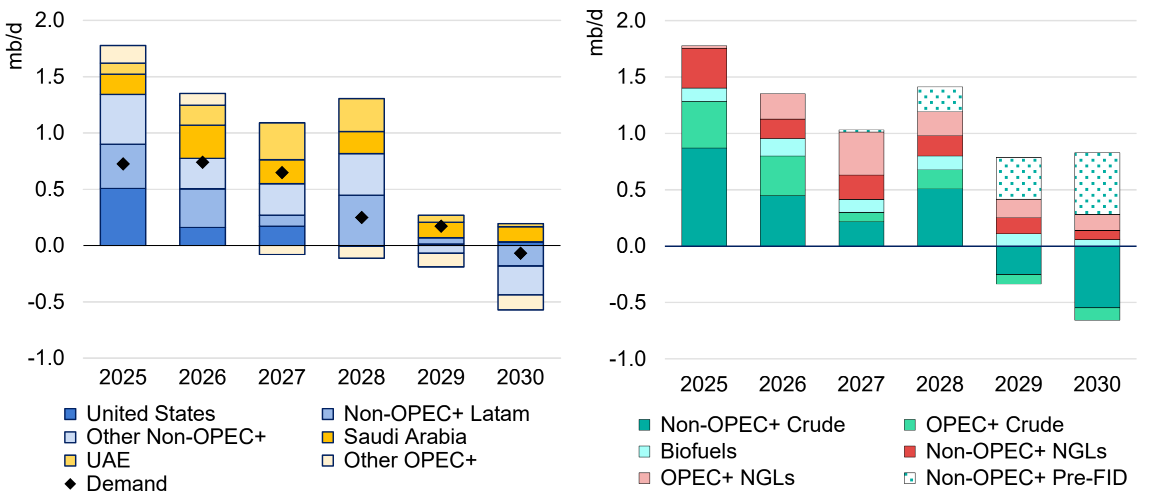
Global summary

Oil production capacity growth dominated by a surge in NGLs, led by the United States and Saudi Arabia

World oil production capacity is forecast to rise by 5.1 mb/d to 114.7 mb/d by 2030, with growth dominated by robust gains in NGLs and other non-crude liquids, and propelled higher by the world's two largest suppliers, Saudi Arabia and the United States. The strategic shift towards increased non-crude capacity is driven by strong global demand for petrochemical feedstocks and the development of liquid-rich gas resources.

Non-OPEC+ producers will provide roughly two-thirds of the global increase, boosting capacity by 3.1 mb/d, while OPEC+ adds nearly 2 mb/d of capacity over the 2024-30 outlook period. The United States will continue to lead the ramp up in non-OPEC+ production, led by strong growth in NGLs, even as its dominance in global supply expansions wanes with shale producers scaling back activity at lower oil prices. Saudi Arabia leads OPEC+ capacity increases, almost exclusively in NGLs. Combined, Saudi Arabia and the United Stated will contribute 40% to total global oil capacity growth in the forecast period.

Global oil supply capacity forecast, year-on-year change, 2025-2030



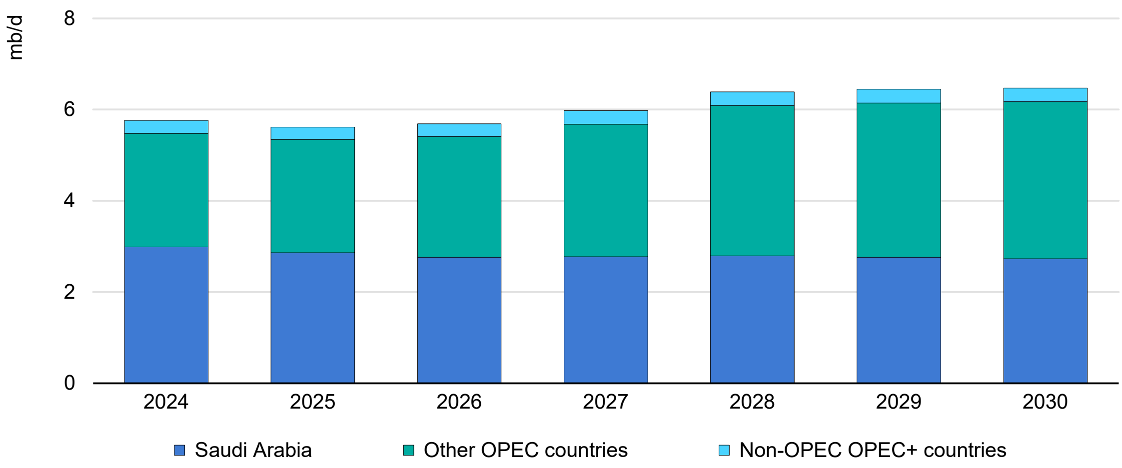
Notes: Assumes Iran, Russia and Venezuela remain under sanctions. OPEC+ NGLs include condensates. Crude includes processing gains and non-conventional volumes. The right-hand chart includes pre-sanctioned projects, listed in the Annex tables.

Total non-crude liquids supply capacity rises by 3.1 mb/d to 2030, of which NGLs account for nearly three-quarters of the increase at 2.3 mb/d. Growing natural gas production from Middle Eastern producers will boost regional NGL supply by 1.4 mb/d to 2030. Despite US light tight oil (LTO) producers cutting spending amid a lower price outlook, increasingly gassy reservoirs will buoy US NGL growth by 860 kb/d. Biofuels are forecast to increase by around 680 kb/d – led by Brazil, India and Indonesia, while non-conventional output and processing gains will add a further 200 kb/d over the forecast period.

By contrast, global crude and condensate capacity expands sharply early in the forecast, underpinned by gains in non-OPEC+ Americas. Overall non-OPEC+ crude and condensate capacity builds by 1.2 mb/d to 2030 despite the number of sanctioned projects tailing off after 2027. OPEC+ net crude capacity, excluding condensates, rises by 820 kb/d, with strong growth in the UAE and Iraq offset by field declines most notably in Mexico.

Net capacity growth through 2030 is roughly twice the projected 2.5 mb/d increase in oil demand over the forecast period. Based on the current OPEC+ supply trajectory laid out at its May 2025 meeting, we estimate OPEC+ spare crude capacity, excluding Iran, Venezuela and Russia, to reach 6.5 mb/d in 2030 and implied stock builds of nearly 2 mb/d at the end of the forecast period. Saudi Arabia holds around half of OPEC+ spare capacity now and it keeps its level roughly steady through the forecast.

OPEC+ spare crude capacity, 2024-2030

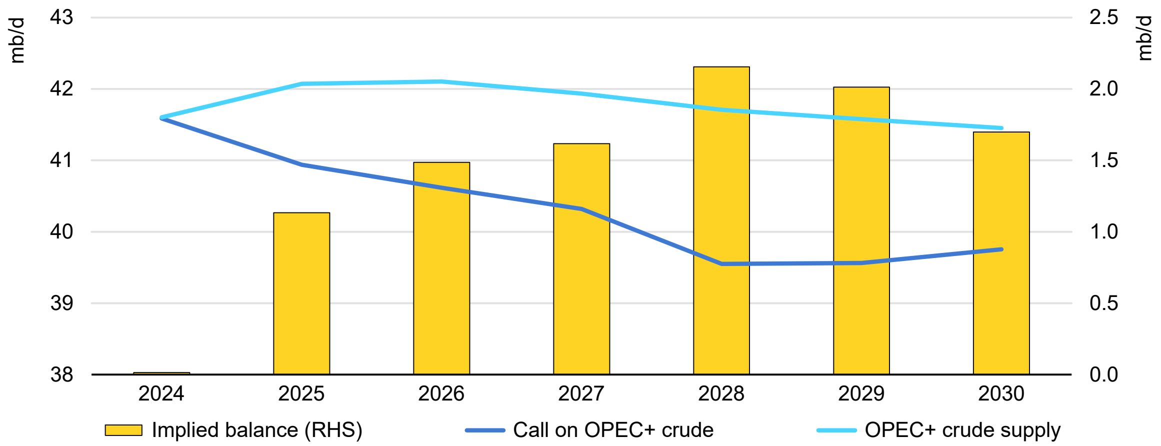


Notes: Based on OPEC+ crude supply targets effective July 2025, excluding Iran, Russia and Venezuela

Non-OPEC+ dominates supply growth

Global oil supply to the market, in contrast to capacity, is projected to rise by 4.1 mb/d to 107.2 mb/d by 2030. Producers in the Americas account for nearly all the 3.1 mb/d growth projected for non-OPEC+ over the forecast period. US LTO supply growth stalls, with output in 2030 only 360 kb/d above 2024 levels. By contrast, Argentinian LTO more than doubles – albeit from a lower base – from 400 kb/d in 2024 to 890 kb/d by the end of the decade. Production growth in Guyana and Brazil will lose momentum from 2028 onwards as the number of sanctioned projects tails off. Meanwhile, new Qatari LNG buildouts and Saudi gas developments bring on more associated NGLs. Taken altogether, these additions, combined with a forecast slowdown in oil demand, will reduce the call on OPEC+ crude oil by 1.8 mb/d from 41.6 mb/d in 2024 to 39.8 mb/d in 2030.

Call on OPEC+ crude oil, OPEC+ supply and implied oil market balance, 2024-2030



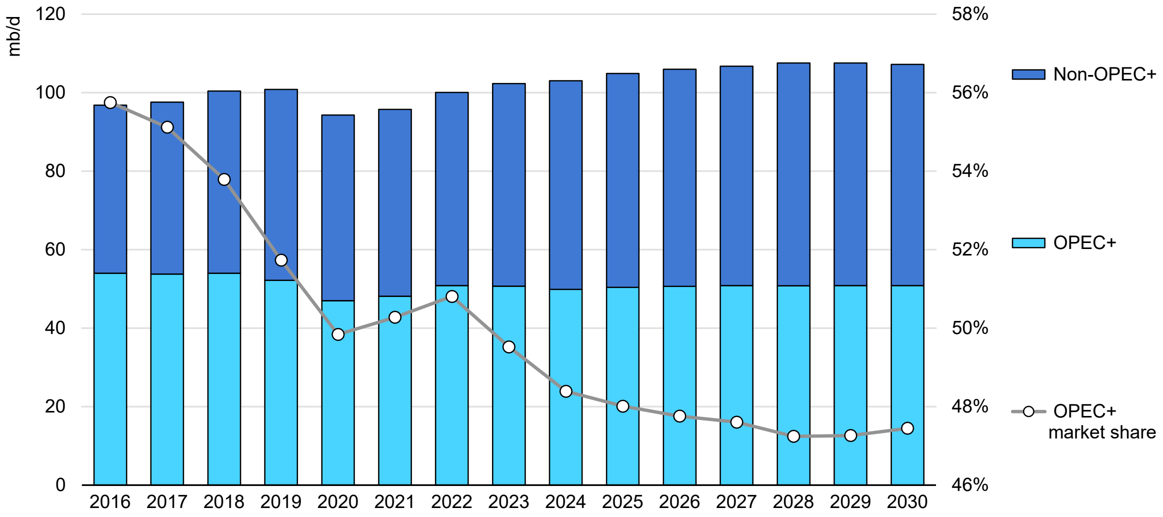
Note: Forecast OPEC+ crude supply based on quota targets effective July 2025.

OPEC+ oil output, including NGLs and condensates, grows by 1 mb/d from 2024 to 2030. For this *Report,* our OPEC+ oil supply outlook is based on the group's crude production level announced on 31 May. The group of eight OPEC+ producers – Saudi Arabia, Russia, Iraq, the UAE, Kuwait, Algeria, Oman and Kazakhstan – that had voluntarily agreed in November 2023 to scale back an additional 2.2 mb/d of production announced 1.4 mb/d of those cuts will be reversed by July. While not all of this supply may hit the market as some members enforce compensation plans, we estimate that only Saudi Arabia has room to substantially raise production, bringing about an additional 180 kb/d onto the market each month from May to July.

Even so, OPEC+ may struggle to regain substantial market share as non-OPEC+ oil supply continues to see robust growth in the early years of the forecast period.

Non-OPEC+ gains slip into contraction after 2028, however, as the pipeline of projects delivered wanes by the end of the decade. This *Report* estimates that an additional 1.1 mb/d of potential pre-FID non-OPEC+ supply, excluding LTO, could come online between 2028 and 2030 should projects move ahead swiftly.

OPEC+ struggles to reclaim market share through the forecast period



Notes: Forecast OPEC+ crude supply based on quota targets effective July 2025. Russia, Iran and Venezuela remain under sanctions. Russian and Iranian production levels are held at current levels through the forecast period. Venezuelan output is assumed to decrease to 600 kb/d by 2026 based on current sanctions. Chart is based on current OPEC+ composition throughout the 2016-2030 period.

World Oil Production by Region (mb/d)

World Oil Production by Region
(million barrels per day)

	2024	2025	2026	2027	2028	2029	2030	2024-30
Africa	7.2	7.4	7.4	7.5	7.5	7.4	7.3	0.1
Latin America	7.4	7.7	7.9	8.0	8.4	8.5	8.3	0.9
North America	28.3	28.9	29.0	29.3	29.3	29.2	29.2	0.9
China	4.3	4.4	4.4	4.4	4.3	4.3	4.2	-0.1
Other Asia	3.1	3.0	3.0	2.9	2.9	2.8	2.8	-0.3
Europe	3.3	3.4	3.4	3.2	3.1	3.0	2.8	-0.5
Eurasia	13.5	13.6	13.7	13.7	13.6	13.5	13.5	0.0
Middle East	30.2	30.6	31.1	31.6	32.1	32.4	32.7	2.5
Total Oil Production	**97.3**	**99.0**	**99.9**	**100.5**	**101.2**	**101.1**	**100.6**	**3.4**
Processing Gains	2.4	2.4	2.5	2.5	2.5	2.5	2.5	0.1
Global Biofuels	3.4	3.5	3.7	3.8	3.9	4.0	4.1	0.7
Total Supply	**103.1**	**104.9**	**106.0**	**106.8**	**107.6**	**107.6**	**107.2**	**4.1**
OPEC Crude	27.2	27.6	27.7	27.7	27.6	27.6	27.7	0.4
OPEC NGLs [1]	5.5	5.7	5.9	6.3	6.5	6.7	6.9	1.3
Non-OPEC OPEC+	*17.1*	*17.1*	*17.1*	*16.9*	*16.7*	*16.5*	*16.3*	-0.8
Total OPEC+	*49.9*	*50.4*	*50.6*	*50.8*	*50.8*	*50.8*	*50.9*	**1.00**
Memo: Call on OPEC+	*41.6*	*40.9*	*40.6*	*40.3*	*39.6*	*39.6*	*39.8*	-1.8

Notes: Forecast OPEC+ crude supply based on quota targets effective July 2025. [1] Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. GTL in Nigeria and non-oil inputs to Saudi Arabian MTBE.

Investment and exploration

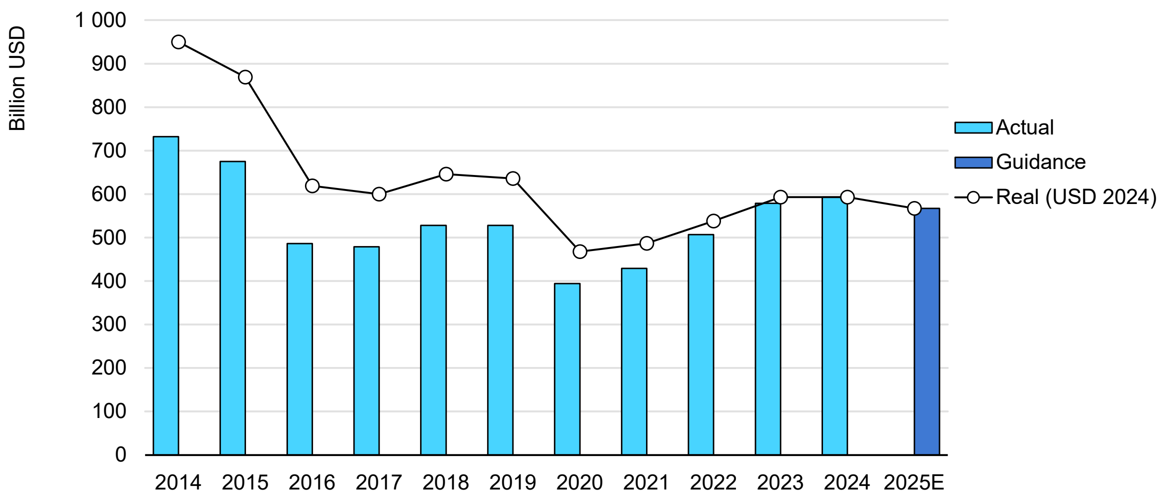
Capex to retreat in 2025 as price risks mount

Global upstream oil and gas investment is set to decline by 4% in 2025, to around USD 565 billion, with US independent shale producers accounting for the majority of the reductions. Upstream oil investments are on track to fall by nearly 6% to USD 420 billion, according to company guidance while spending on gas increases 3% to USD 145 billion. Recent oil price fluctuations, financial market volatility and trade uncertainties could further impact development costs and investment decisions.

In 2024, global upstream oil and gas capex was flat in nominal terms at USD 590 billion, and down by USD 10 billion in real terms, compared to 2023 levels. Nominally, 2023 to 2025 capex levels are at the highest level since 2015, but still below 2019 in real terms.

Global upstream investment continues to reflect more cautious capital deployment across the industry, as it has since 2015. Companies no longer pursue aggressive growth, and instead place greater emphasis on capital discipline, profitability and cost optimisation. This mantra has perhaps intensified in the past twelve months.

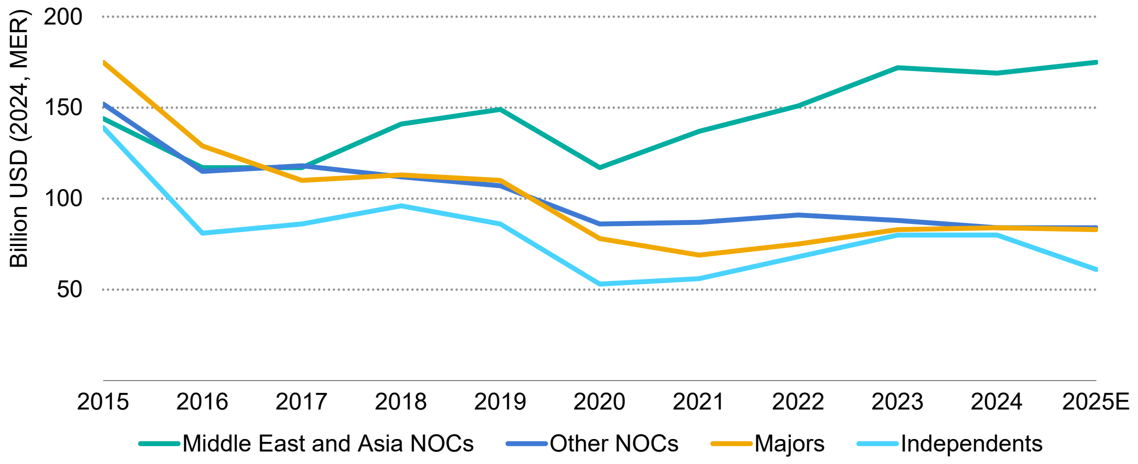
Global upstream oil and gas capital spending



Source: IEA, World Energy Investment 2025.

Investment priorities are given to high-potential, low-cost basins such as those in West Africa, deepwater Latin America and the US federal offshore. In developed offshore basins, exploration activity focuses near existing infrastructure to lower development expenditures. Despite the broader trend of investment restraint, upstream spending continues to rise in the Middle East and among certain major oil companies, underscoring their strategic focus on long-term resource development.

Global upstream oil and gas capital spending by operator segment



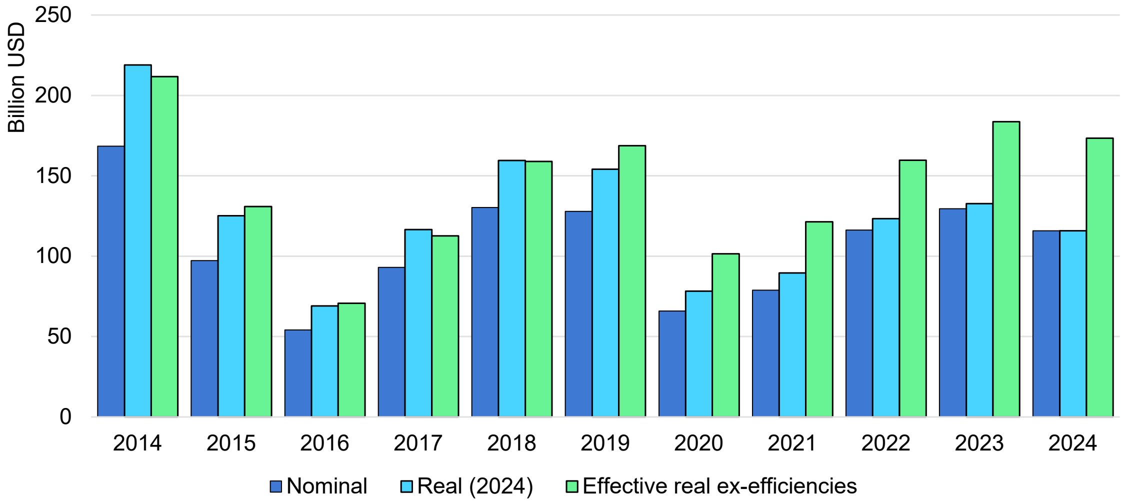
Source: IEA, World Energy Investment 2025.

The increase in upstream investment in 2024 was largely concentrated in projects by national oil companies (NOCs) in the Middle East, China and the Americas. Middle Eastern and Asian NOCs accounted for over 60% of the global capex spend this decade, up 10% from a decade ago. Saudi Aramco increased its upstream capex by 19% y-o-y to USD 39 billion in 2024, primarily to maintain its 12 mb/d of crude oil production capacity and grow its natural gas, NGLs and condensate output. In the UAE, the Abu Dhabi National Oil Co (ADNOC) plans to raise crude supply capacity to 5 mb/d by 2027, spending USD 150 billion between 2024 and 2027 to achieve this goal.

Upstream investment among international oil companies (IOCs) held relatively steady in 2024, and is expected to remain flat in 2025. However, levels are still well below those seen a decade ago, in part due to a reduction in offshore facility spend and in part due to cost deflation, with 2024 cost indexes still only at 80% of 2014 levels.

Capital expenditures by US independents have recovered since 2020 but remain below pre-Covid levels on a real and nominal basis as LTO capex has not fully returned. Analysis of well productivity gains in the shale patch shows that since 2014 hard-won efficiencies have saved a cumulative USD 220 billion of capex, of which USD 60 billion accrued in 2024. In other words, had drilling and completion operations' capital efficiency stayed static since 2014, to deliver the same amount of footage drilled and completed US shale spend would have been USD 175 billion in 2024, not USD 115 billion.

US upstream tight oil and gas capex and the impact of well efficiencies, 2014-2024



Notes: Efficiencies taken as change in feet drilled per day and feet completed per day normalised to Q1 2014 then applied on a capital weighted basis by basin. Capital allocation for US LTO assumed at 30% for drilling, 60% for completions and 10% for facilities. Facility efficiency held constant.
Sources: IEA analysis based on data from the US EIA, Rystad Energy's ShaleWellCube and UCube.

Projects, declines and resources

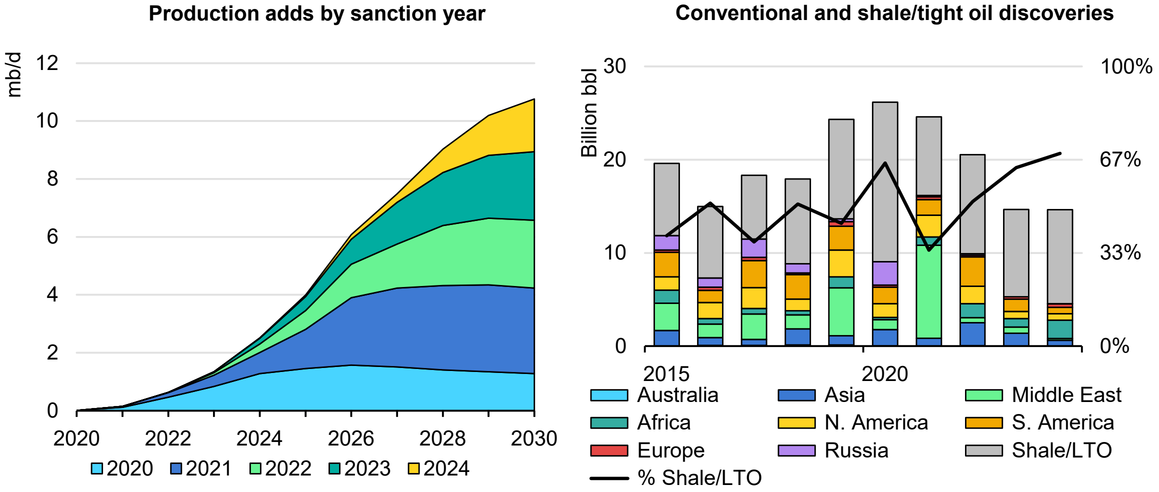
Peak production from conventional projects sanctioned during 2021-24 is expected to average 2.5 mb/d on annual basis, with the 2024 cohort of sanctioned projects adding 2.2 mb/d of annual supply by 2032. This slightly exceeds the 2015-19 previous five-year average peak output of 2.1 mb/d.

Less encouraging has been the result of global exploration efforts over the last decade. Average exploration capital from 2015-24 was 30% lower than the previous ten-year average, at USD 35 billion. Additionally, the correlation factor between exploration capex and oil prices changed from 0.9 over 2000-14 to effectively zero from 2015-24, corresponding with the rise in US LTO. Indeed, the percentage of discovered resources being shale/tight oil has increased from 40% of the global total in 2015 to close to 70% in 2024.

According to Rystad Energy, just under 5 billion barrels of conventional liquid resources were discovered in 2024 – replacing 19% of the conventional production last year. Furthermore, just four projects accounted for approximately half of the discovered volumes. Namibia saw two large discoveries, including Galp Energia's 900 million barrels of oil-equivalent (boe) Mopane and TotalEnergies' 500 million barrels (mb) add at its Venus oil field. ExxonMobil added 400 mb at its

Stabroek Block in Guyana. Rounding out the top five were two Eni discoveries – both 175 mb – at Saasken-Sayulita in Mexico and Calao in Côte d'Ivoire.

Conventional production additions by sanction year and discoveries by region



Source: IEA analysis based on Rystad Energy UCube data.

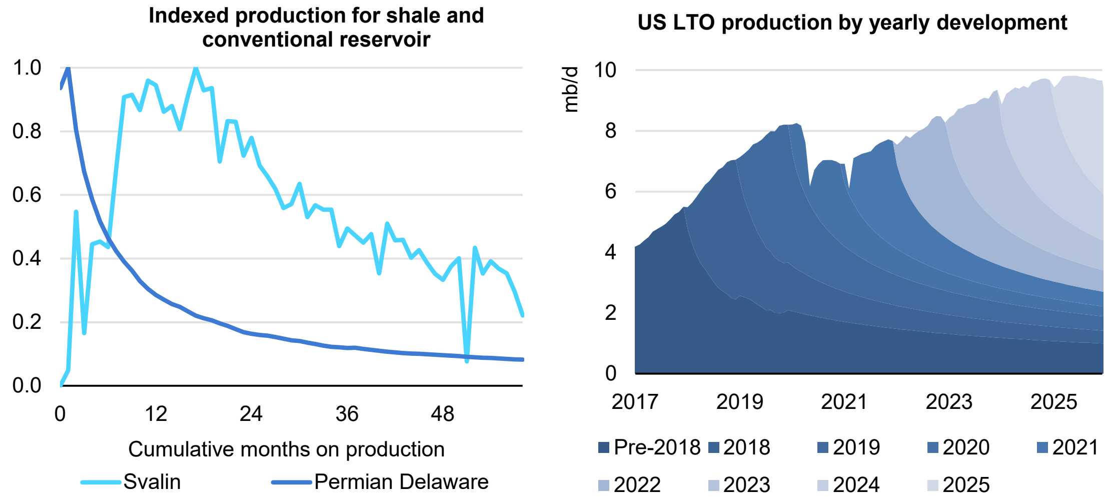
While conventional discovered resources volumes are decreasing, companies are reallocating capital and operating expense (opex) dollars to stem output losses at producing fields. Well capex and field direct opex levels are key determinants of decline rates. Analysis of Rystad Energy data shows that 2024 saw the highest ever level of field direct opex. These investments are critical for operators to maintain existing wells and facilities, as well as for boosting short-term supply by increasing incremental recovery from producing reservoirs through sidetracks, major well workovers and other well interventions. Nominal well capex and field direct opex in 2024 was close to 90% of 2014 highs and the third highest in the history of the industry, whereas facility capex still sat at 75% of its 2014 peak.

This rotation in capital allocation has been due to the shift toward short-cycle investment in shale wells and infrastructure-led offshore expansions, both of which inherently have higher percentages of spend directed towards wells. Additionally, there have been savings in facility spend thanks to a push towards standardisation and 'right-sizing' offshore facilities compared to the last decade.

Observed decline rates at mature fields, accounting for all capex and opex, average close to 6% globally, meaning that around 5 mb/d of supply needs to be replaced annually to hold production flat. The increase in opex since the 2020 nadir has helped hold replacement volumes steady even as more output comes from high-decline shale barrels.

Between January and December 2024, there was a 2.8 mb/d decline in production from existing US shale wells on a base of 8.2 mb/d, while the remainder of non-OPEC+ oil output declined by 2 mb/d on a 40 mb/d base. Due to the high initial decline rate of shale wells compared to conventional wells, continuous drilling and fracking is required to maintain production, and key to determining the path of global supply and investment. The Q1 2025 Dallas Federal Reserve Energy Survey recently noted that for operators in its region (primarily the Permian and Eagle Ford), existing wells need an average of USD 41/bbl to cover operating expenses and USD 65/bbl to profitably drill new wells.

Indicative field declines and US LTO by development year



Notes: Permian Delaware median well type-curve. Svalin is a Norwegian Paleocene sandstone reservoir developed in a single stage with no additional development during the period shown. Production is indexed with peak output equal to 1.
Source: IEA analysis based on historical data from Rystad Energy ShaleWellCube and Norskpetroleum.

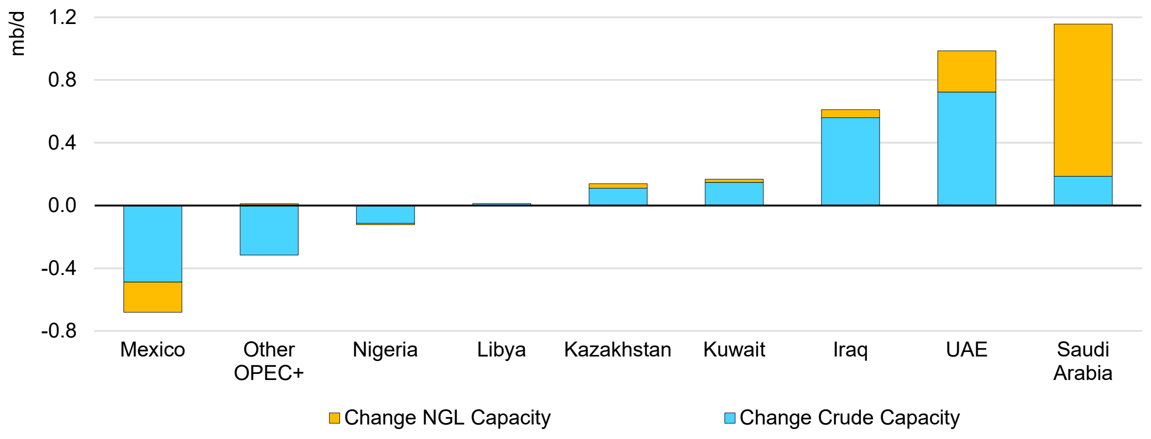
OPEC+ supply

Middle East boosts OPEC+ capacity gains

OPEC+ oil production capacity, including condensates and NGLs, is forecast to grow by a net 2 mb/d from 2024 to 2030, led by Saudi Arabia, the UAE and Iraq (see Table 6 in Annex). Growth in OPEC+ condensates and NGLs capacity – not subject to quotas – comprises over 60% of the net additions, primarily from the first development phases of Saudi Arabia's giant unconventional Jafurah field. The increase in NGLs and condensate output corresponds with the country's strategy to increasingly shift to natural gas production to reduce crude use in power generation, boost feedstocks for expanding petrochemical supply chains and build out NGLs export capacity.

OPEC+ net crude capacity rises by over 810 kb/d between 2024 and 2030. Kazakhstan leads the expansion early in the forecast, following the January 2025 start-up of its Tengiz expansion (260 kb/d). Together, the UAE and Iraq increase crude capacities by 1.3 mb/d from 2024 to 2030, while Mexico is set to dominate total oil capacity losses globally, declining by 630 kb/d to 1.3 mb/d.

Selected OPEC+ crude and NGLs production capacity changes, 2024 vs 2030



Note: Other OPEC+ = Algeria, Azerbaijan, Bahrain, Brunei, Congo, Equatorial Guinea, Gabon, Malaysia, Oman, South Sudan and Sudan. Iran and Venezuelan capacities are held constant over the forecast. OPEC+ NGLs include condensates.

Total oil production from the OPEC+ alliance fell by 800 kb/d to 49.9 mb/d in 2024. Saudi Arabia led the declines, cutting output by 480 kb/d on average, while Kuwait trimmed 110 kb/d. Production disruptions and outages hit Russia (-260 kb/d), Mexico (-130 kb/d) and Libya (-90 kb/d). Iran and Venezuela, both exempt from supply quotas, boosted output by a combined 530 kb/d on the year, running at their highest levels since 2019. NGLs output from the group, including condensates, reached 8.2 mb/d in 2024. NGLs and condensate supplies from Middle East OPEC+ producers are expected to rise by 1.4 mb/d by the end of the decade, to reach 6.8 mb/d, with Saudi Arabia alone set to increase by 970 kb/d.

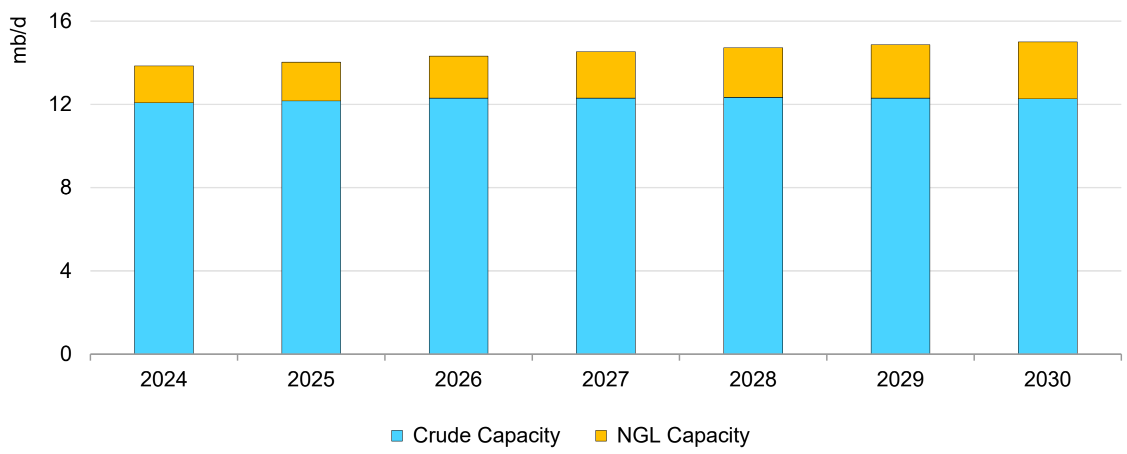
The group of eight OPEC+ countries – Saudi Arabia, Russia, Iraq, the UAE, Kuwait, Algeria, Oman, Kazakhstan – that agreed in November 2023 to cut production by 2.2 mb/d saw their market share decline from 39% in 2022 to 36% in 2024. While overall compliance has been mediocre (in 2024 Russia, the UAE, Iraq and Kazakhstan overproduced by an average of 1.2 mb/d), Saudi Arabia has shouldered the bulk of cuts, with its spare capacity rising to 3 mb/d.

This group of eight countries announced three substantial monthly target increases since April 2025, reaching a total of 1.4 mb/d for the May-July period. Given current levels of overproduction and capacity limits, we assess that only

Saudi Arabia has room to pump substantially higher volumes, bringing an additional 180 kb/d each month on the market from May to July. OPEC+ has noted that it may revise guidance on production levels based on changing market conditions, therefore we have maintained OPEC+ production levels effective from July 2025 and included increased output only for countries producing below their monthly production targets and with spare capacity.

Saudi Arabia is set to lead OPEC+ overall capacity growth through the end of the decade, gaining almost 1.2 mb/d. Saudi total oil production declined by 500 kb/d y-o-y to 10.9 mb/d. In early 2024, Saudi Aramco downgraded its 13 mb/d crude capacity goal to a 12 mb/d maintenance plan (excluding Neutral Zone production). At the same time, it shifted its focus to develop its natural gas resources as well as renewable energy supply, which will allow the country to reduce its reliance on oil burn for power generation. Aramco envisions over 4 bcf/d growth in gas capacity from 2024 to 2030. Coupled with the build-out of renewables, this will displace around 1 mb/d of oil used in power plants of which 500 kb/d is crude oil (*see Saudi plans lead push to slash oil-fired electricity generation*). Phases 1 and 2 of the massive Jafurah unconventional resource play account for half of the growth in natural gas capacity plus a 270 kb/d gain in ethane and 630 kb/d of NGLs and condensates by the end of the decade.

Saudi Arabia crude and NGLs production capacity, 2024-2030



Notes: Crude capacity includes Saudi Arabia's share of Neutral Zone production. NGLs capacity includes condensates.

While Saudi Arabia's crude oil production capacity is largely steady over the forecast period, Aramco is investing heavily to offset field declines. Over 1.2 mb/d of crude maintenance projects are reported to come onstream between 2025 and 2026. The Dammam Phase 1 water injection project of 25 kb/d is slated for a 2025 start-up followed by a 50 kb/d incremental Phase 2 in 2027. Offshore crude megaprojects, Berri and Marjan, are scheduled to bring 550 kb/d of combined production onstream, with NGLs processed at the Tanajib Gas Plant. Tanajib is planned to handle 2.6 bcf/d of natural gas offtake from the Marjan and Zuluf fields. Arabian Heavy crude grades will see a lift from 2026 onwards with the commissioning of the 600 kb/d Zuluf central processing facility. The additional heavy crude supply would offset losses of Mexican heavy grades over the forecast period.

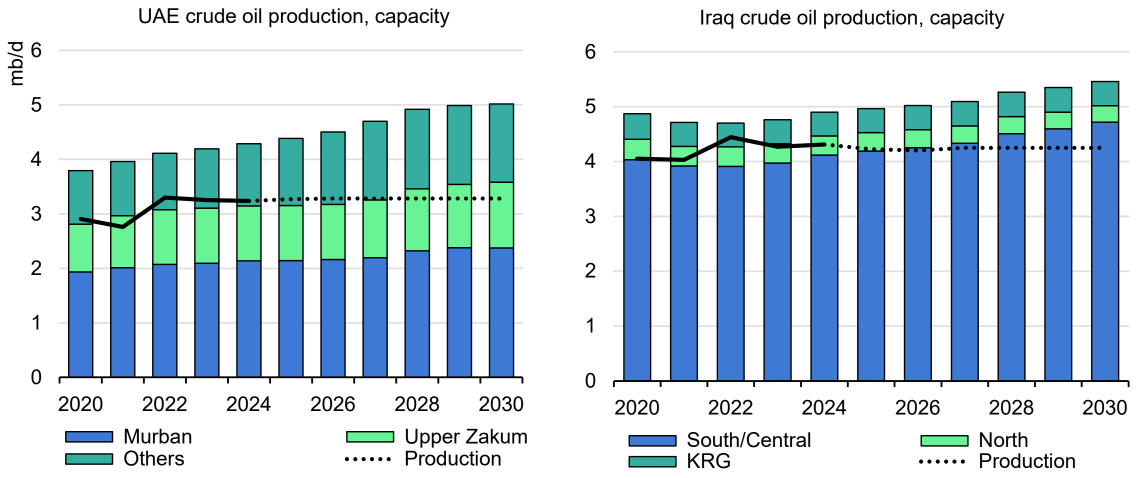
The **UAE** is set to lead global crude oil capacity additions, adding over 720 kb/d by 2030. The country will also increase NGLs capacity by 260 kb/d as it charts its path to become a natural gas net exporter by 2030. Oil production, including NGLs and condensates, was roughly flat at 4.2 mb/d in 2024. The Emirati's ambitious 5 mb/d crude capacity plan by 2027 received a boost last month after agreements were signed with operator ExxonMobil and partner INPEX/JODCO for the Upper Zakum expansion project, designed to raise production by 200 kb/d to 1.2 mb/d.

The Abu Dhabi National Oil Company's (ADNOC) investments have focused on offshore crude capacity growth in recent years. Efforts to boost Upper Zakum supply have lifted output over the last decade from about 500 kb/d to 1 mb/d. Last year, the 45 kb/d Belbazem offshore block started up. Contracts have also been awarded to develop incremental production, including the 20 kb/d project to help stabilise output at the 450 kb/d Lower Zakum field, with a further 50 kb/d expansion planned by 2027. At the Umm Shaif field, an uplift of 115 kb/d, split into three separate phases, is scheduled to raise capacity to 390 kb/d by 2027.

Recently, attention has turned back onshore with planned incremental capacity projects at Bu Hasa (+100 kb/d) and the Bab field (+90 kb/d). Like Saudi Arabia, the UAE is actively appraising its unconventional resources. In onshore Abu Dhabi, ADNOC Drilling is utilising its Turnwell joint venture, in partnership with SLB and Patterson-UTI, to drill over 140 wells by the end of 2025 and test the extent and productivity of the country's unconventional resources. In May 2025, EOG Resources, one of the largest US shale producers, signed exploration licenses for the massive Unconventional Onshore Block 3 in the Al Dhafra region. While no additional unconventional capacity growth volumes are held in our forecasts, success could support the UAE's crude and gas ambitions.

With the Emirates targeting gas self-sufficiency by 2030, ADNOC Gas is raising its natural gas processing capacity with an associated increase in NGLs. The Maximising Ethane Recovery and Monetisation (MERAM) project, expected to start-up in late 2025, will extract around 120 kb/d of ethane at Habshan that can be used as feedstock at Borouge's expanding fleet of steam crackers. Several upcoming projects, including the 1.5 bcf/d Rich Gas Development and 1.8 bcf/d Bab Gas Cap project, have had contracts recently awarded and their liquids capture are not yet included in capacity estimates.

UAE and Iraqi crude oil production and capacity, 2020-2030



Note: Forecast production for 2025-2030 is based on OPEC+ supply targets effective July 2025 and estimated levels of compliance.

Iraq is forecast to increase its capacity by 560 kb/d to 5.4 mb/d by 2030, short of its 6 mb/d target. Crude expansion plans are hindered by a lack of water injection capacity, midstream challenges and limited export capacity from its southern fields. Most capacity growth is driven by foreign companies working in the south as Iraq seeks to streamline the Basra port and provide alternative crude export options. The recent re-entry of BP at the Kirkuk field, after its 2019 exit, and the potential re-opening of the Iraq-Türkiye Pipeline (ITP), provide options for longer-term gains. The country's total oil production gained 40 kb/d y-o-y to reach 4.5 mb/d in 2024.

A lack of water injection capacity for pressure support across many Iraqi fields constrains the country's ability to increase production. TotalEnergies is developing infrastructure and local capabilities at its 5 mb/d seawater treated injection project for the southern fields of Zubair and West Qurna. The company also intends to raise output at the Ratawi oil field from 85 kb/d to 210 kb/d.

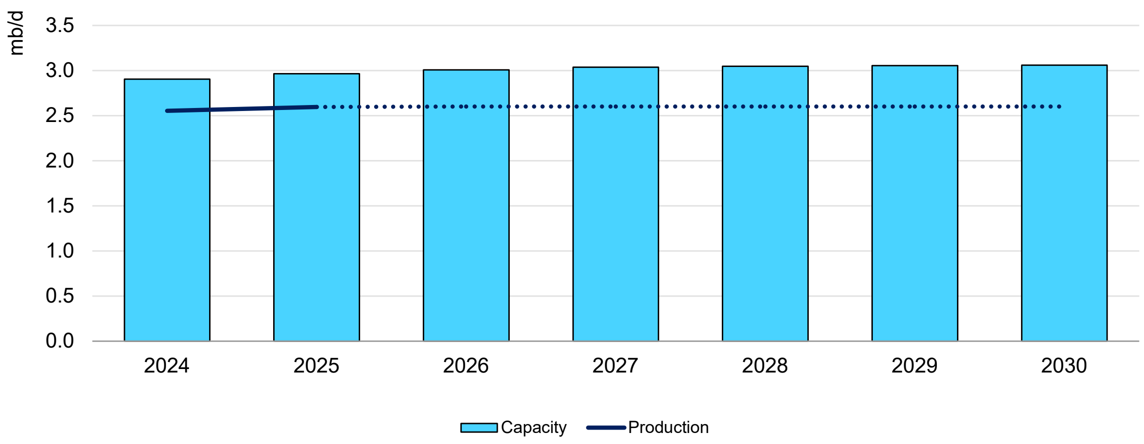
Iraq has made significant strides in the last year to debottleneck the Basra port. In April, Basra Oil Company signed a contract with Italy's Micoperi and the Turkish firm ESTA to build a third subsea export pipeline, design capacity 2.4 mb/d, and construct loadings options including a floating single point mooring platform. At the end of 2024, the Iraqi government approved the 2.25 mb/d capacity, 685 km Basra-Haditha pipeline project that will run parallel to the dilapidated 800 kb/d Strategic Pipeline. The new line will act as a conduit for oil from the Basra region to demand centres in central Iraq and, in the long-term, could connect southern fields to northern export routes.

Including Ratawi, Iraq has over 1.2 mb/d of potential capacity additions in different phases of maturity being worked across southern fields. For example, PetroChina is proceeding with expansion plans at West Qurna-1 to raise production from a reported 550 kb/d towards 800 kb/d near the end of the decade, but no formal project sanctioning has been announced. In late 2023, Lukoil and Baghdad agreed to extend the service contract for the West Qurna-2 field to 2045, with plans to gradually boost capacity from 480 kb/d to 800 kb/d. Eni continues work on the 250 kb/d expansion at the 450 kb/d Zubair field. Basra Oil Company is progressing work on Majnoon, currently producing around 130 kb/d, to reach 450 kb/d, but project delays have continued to plague the field's expansion.

The northern Kirkuk oil fields and the capacity that is controlled by the Kurdistan Regional Government (KRG) may see a resurgence in the coming years if shipments of 450 kb/d along the ITP to Ceyhan ultimately resume following long months of negotiation between Federal Iraq, the KRG, and foreign oil companies in the north and Türkiye. Flows on the line have been halted since the end of March 2023, but around 300 kb/d is reportedly moving into the local market or trucked across Iraqi borders. BP stopped work on the Kirkuk re-development in 2019 due to security concerns, but its recent re-entry may buoy output from the world-class resource into the next decade.

Kuwait is projected to deliver a 150 kb/d increase in capacity to nearly 3.1 mb/d by 2030, while endeavouring to deliver its 3.5 mb/d capacity target by 2035. Annual average crude oil production in 2024 slipped 110 kb/d to 2.55 mb/d including contributions from the Neutral Zone. Kuwaiti capacity has been on the decline, losing 220 kb/d since its peak in 2018.

Kuwait crude oil production and capacity, 2024-2030



Note: Forecast production for 2025-2030 is based on OPEC+ supply targets effective July 2025 and estimated levels of compliance.

Kuwait Oil Company (KOC) has focused its attention to the south at its giant, 80-year-old Burgan oil field, but efforts to stem declines have proven challenging. Last year, KOC brought on the northern Jurassic gas development, adding about 50 kb/d of light crude oil capacity. Gains at the Ratqa heavy oil field, supported with technical work by Shell, are boosting capacity by another 20 kb/d this year. Recent exploration success offshore Kuwait may yet provide a more direct path to achieving the country's 2035 targets.

Capacity in the Neutral Zone, shared equally between Kuwait and Saudi Arabia, is expected to remain around 260 kb/d for each country through 2030. Recent strides to increase production could add some upside, however.

Oil output in **Oman**, including condensates and NGLs, was around 1.1 mb/d in 2024. Omani capacity is forecast to increase by 40 kb/d over the outlook period with continued investments in heavy oil fields and offshore developments including Yumna offshore. A recently signed USD 30 billion agreement with Occidental Petroleum, extending its development plans for the Mukhaizna field, is expected to help curb declines. Oman's focus on natural gas, including the anticipated start-up of Marsa LNG's 1 Mtpa train in 2028, will provide a small boost to the country's condensate and NGL supply.

Looming Caspian capacity declines for Kazakh and Azeri crude by 2030

In **Kazakhstan**, total oil supply in 2024 edged lower by 50 kb/d y-o-y to 1.9 mb/d, due to maintenance at its largest producing fields Tengiz, Kashagan and Karachaganak. The Future Growth Project (FGP) at Tengiz, led by Chevron, has expanded field capacity by 260 kb/d to 860 kb/d in January 2025, bringing overall crude capacity to 2.1 mb/d. Following the 2023 launch of the Tengiz Wellhead Pressure Management Project and the FGP start-up, Tengiz now accounts for over 40% of Kazakh oil output. Kazakh crude capacity is projected to fall to 1.9 mb/d by 2030 until larger field expansions, such as those at Kashagan, are given a firm go-ahead.

In October 2024, the Kazakhstan senate further strengthened ties with Qatar, approving the establishment of a long-term strategic partnership across key sectors including energy and agriculture. Agreements were sanctioned for QazaqGaz and UCC Holdings, a major Qatari construction and infrastructure company, to finish a 100 million standard cubic feet per day (MMscf/d) sour gas processing plant that supports the Kashagan Phase 2A development. The plant and its associated pipelines will help raise crude capacity by an estimated 25 kb/d to 440 kb/d, with a reported start-up in late 2026. Agreements for subsequent gas plants associated with the Kashagan development were signed but are not yet assumed as firm in the forecast

Azerbaijan's total oil supply dipped 20 kb/d in 2024 to 600 kb/d. Output stays at roughly this level as BP continues to ramp-up the 100 kb/d capacity Azeri Central East (ACE) offshore platform over the next few years. ACE, along with Shah Deniz compression, is expected to help bolster the country's total oil capacity in the near-term and cushion declines before slumping to 520 kb/d by 2030.

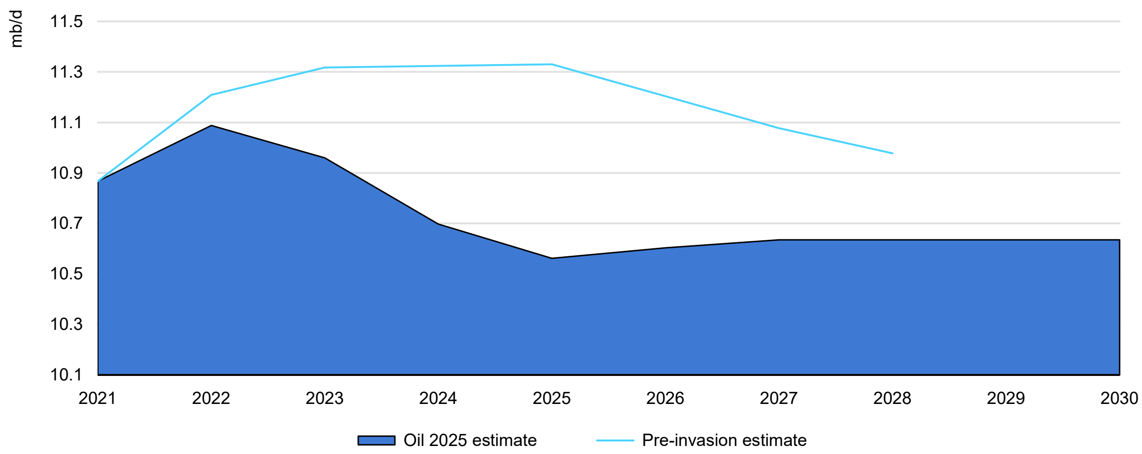
Sanctions stifle capacity gains but barrels still flow

The increased tensions between Iran and Israel and the impact of western sanctions on Russia, Iran and Venezuela remain a key uncertainty in our forecast. Access to technologies, financing and supply chain inputs, as well as changes as to who is buying sanctioned barrels, may be further impacted depending on the outcome of ongoing negotiations. For Russia and Iran, we have held capacity and production at current levels throughout the forecast period. In the case of Venezuela, current sanctions guidance from the US government has put a dent into the country's production capacity outlook.

Russian oil production dipped by a further 260 kb/d in 2024, to 10.7 mb/d, taking total production losses since the outset of the invasion of Ukraine to 600 kb/d. Nonetheless, the Russian oil sector has proven surprisingly resilient, with reports of western Siberian drilling ticking up. Yet sanctions appear to have muted near-term growth ambitions. We hold Russian capacity broadly flat at 10.9 mb/d to 2030, but further delays to Rosneft's giant, 600 kb/d Vostok Oil project may dampen Russian output in the medium term. Significant strides in building up domestic supply chains and key technologies, such as heavier drill rigs to target longer horizontal wells and development of new fracking completion fluids, have supported efforts to sustain production, but a dearth of equipment for hard-to-recover reserves in the Arctic and lack of shipbuilding technologies have pushed back the start-up of key projects. The war and the resulting economic impact have also held back investment due to all-time high interest rates, higher corporate taxation and tight Russian labour markets.

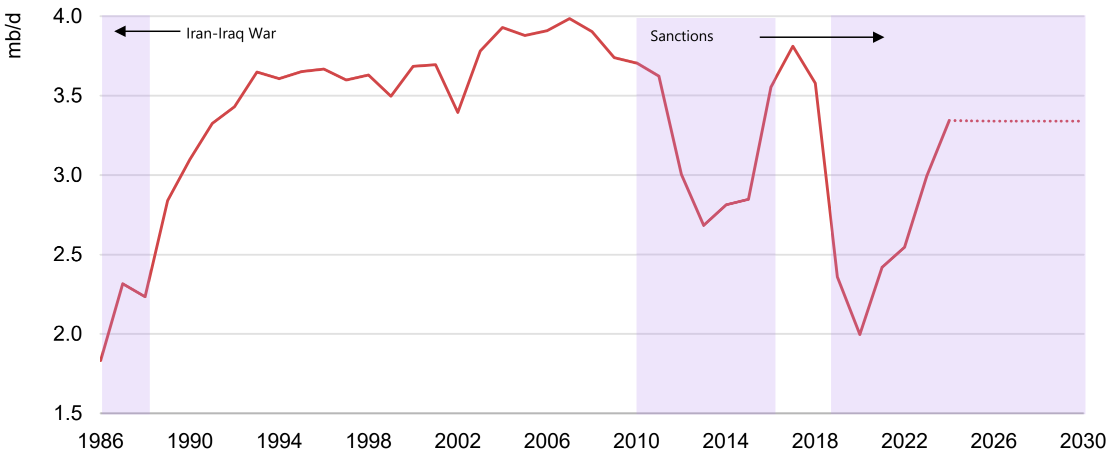
Moscow's Arctic reserves could provide a significant boost to capacity, but this has proven difficult amid tightening sanctions. In Q1 2025, Rosneft pushed back the start-up of its Vostok Oil project from 2024 to 2026. Development of Vostok is split roughly evenly between the currently producing Vankor and nearby Suzunskoye and Lodochnoye fields, with the other half from Payakha, Ichemminskoye and Baikalovskoye. While oil reserves for Vostok Oil were bumped up last year by nearly 10% to over 50 billion barrels, the ability to export oil from the fields is constrained. Progress continues on the 770 km pipeline, with just under half completed at the end of 2024, and on the receiving oil terminal at Sever Bay on the Arctic Kara Sea. Arctic LNG-2 has been scaled back and delayed from 2026 to 2028 as Novatek works on a liquefaction technology and sources LNG icebreaker tankers.

Russia estimated total oil supply, 2021-2030



Iran's oil supply has, thus far, continued to flow at a relatively robust levels in the face of increasing US sanctions and tensions with Israel, making it the second largest source of supply growth after the United States for two years running. Total oil production last year reached its highest level since 2017, rising 420 kb/d y-o-y to 4.7 mb/d, of which 1.3 mb/d was condensates and NGLs. Crude exports averaged 1.6 mb/d in 2024. Nearly all Iranian oil exports land in China, with crude destined for use in independent "teapot" refineries. US sanctions have grown progressively more severe in recent months with nearly all aspects of Iranian supply chains currently targeted.

Iran crude oil production, 1986-2030



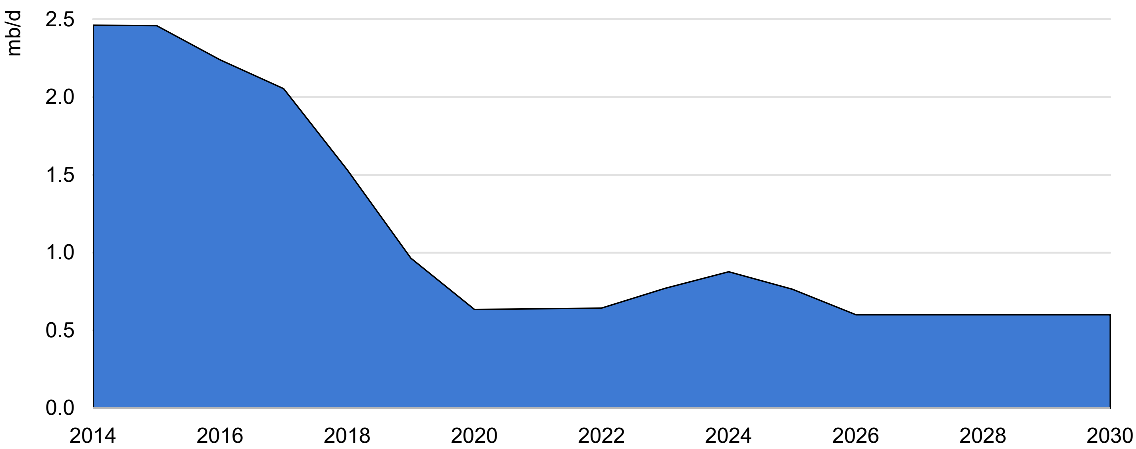
The ramp-up in Iranian output has left the country with slim spare capacity. Tehran relies heavily on domestic firms to try to stem field declines. Since the start of last year, Iran has awarded over USD 33 billion worth of contracts locally to raise production from its natural gas and oil fields. Additionally, the country continues to make strides to develop its capabilities to manufacture and operate technologies critical for improved oil recoveries, such as large field compressors.

There are several sources of Iranian capacity growth on the horizon with its core West Karun fields, together with Yaran and Yadavaran, capable of driving around 1 mb/d of growth. Contracts were awarded in March 2024 to expand onshore field capacity, aimed at raising production from 400 kb/d to 620 kb/d. Iran is also working on options to increase output at smaller fields in West Karun, including Jofeyr and Sepehr.

Oil continues to flow, on pace with 2024 levels, but recent hesitancy from Chinese buyers has reduced crude imports from Iran by 30% in May over last year's average. Ongoing negotiations with the United States on the future of Iran's nuclear programme cast a shadow of uncertainty on the path forward for sanctions. Swift enforcement of US sanctions in 2018 slashed Iranian crude exports from an average of 2.2 mb/d to less than 500 kb/d but enforcement of US sanctions this time around has proven more challenging.

Venezuela increased its total oil supply by nearly 110 kb/d last year, to 960 kb/d, its highest level since 2019. Venezuelan crude capacity is estimated at over 1 mb/d in 2025, with the largest capacity gains from western fields (+30 kb/d) and heavy oil producers (+70 kb/d), including joint ventures with Chevron, China National Petroleum Company (CNPC) and Rosneft.

Venezuela crude oil production, 2014-2030



In Q1 2025, the United States announced it was reversing the US Department of Treasury's Office of Foreign Asset Control's (OFAC) 2022 Venezuela General License 41 (GL 41) effective 3 April, and other licenses that had allowed western companies including Chevron, Eni, Repsol and others to operate, trade and pay taxes in Venezuela. The United States doubled down on 2 April, announcing secondary sanctions on buyers of Venezuelan oil. Chevron's general license expired on 27 May. Western operators in the country continue to discuss their path forward with the US government.

PDVSA is highly dependent on diluent imports (particularly naphtha or light condensate) for blending Venezuelan heavy crude which constitutes over half of the country's crude capacity. While imports of diluent dipped after the latest US announcements, new supplies from Russia, China and Iran have been sourced since May. The establishment of new diluent supply chains not reliant on western sources allows Venezuela to maintain its upstream activities. However, the risk of secondary sanctions and US tariffs on buyers of Venezuelan oil has slowed oil exports by 220 kb/d since February. While the situation remains fluid, we have assumed crude production declines of 30 kb/d per month to 600 kb/d by year-end.

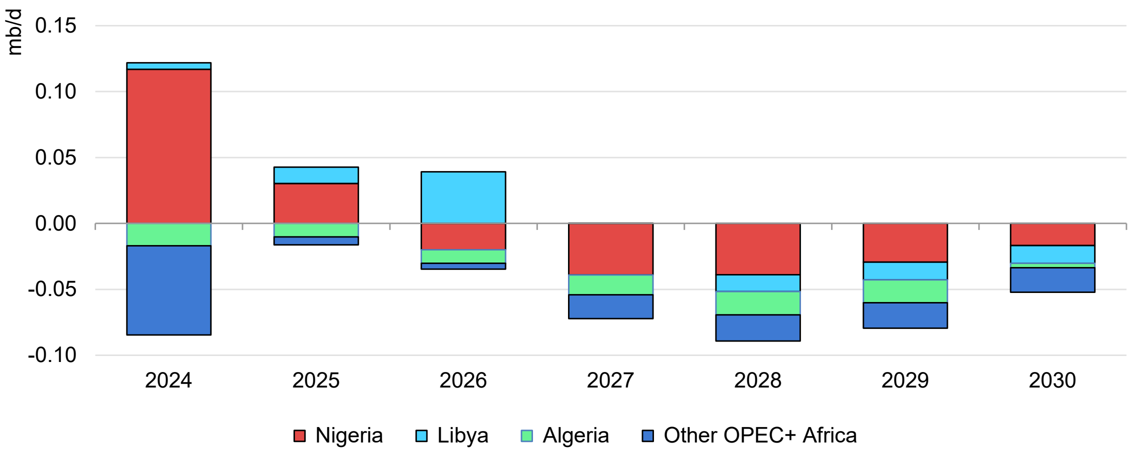
African OPEC+ members entice foreign interest

African OPEC+ members are expected to see crude capacity fall by 260 kb/d to 4.2 mb/d by 2030, largely due to difficulties in attracting investments needed to offset field declines and raise production. However, recent changes to contract terms in several countries may yet encourage foreign capital inflows towards the end of the decade. In Nigeria, a broad series of reforms across the petroleum sector were introduced in 2024 and 2025, including new tax incentives for deepwater exploration and production, and the first fiscal framework changes since 1991. Algeria revised contracts for its auction last year, reducing government take by about one-third. Libya, as part of its first exploration round in 18 years, introduced a new production sharing agreement that could see foreign company returns increase from 2.5% up to 35.8%.

Nigerian total oil production ticked up markedly towards the end of 2024 to 1.6 mb/d, at 1.4 mb/d of crude and 210 kb/d of condensates, in part due to concerted government action against theft and sabotage and supported by the start-up of the Utapate field (+40 kb/d). In our 2024-30 forecast, Nigerian crude oil capacity is projected to average near 1.6 mb/d in the next few years based on plans to sustain production at existing projects. Further out, sanctioned projects will help slow, but not reverse, steep declines, with crude capacity ending the decade just below 1.4 mb/d.

President Bola Ahmed Tinubu, elected on promises of reform to the country's energy sector in May 2023, implemented major policy, regulatory and fiscal reforms aimed at revitalising investment in the country's oil and gas sector. The government's new policies mark a seismic shift to focus on the country's rich oil and gas offshore, with more favourable contract, fiscal and tax terms for investors. Changes in the framework of production sharing contracts (PSC) and joint operating agreements (JOA) are intended to remove bureaucratic bottlenecks, streamline licensing processes, provide improved fiscal terms for deepwater developments, and incentivise production of natural gas and its associated liquids. Additionally, in April President Tinubu dissolved the board of the Nigerian National Petroleum Company and appointed a new board and executive leadership team, with a mandate to enhance operational efficiency and commercial viability. The government has set highly ambitious targets for the country's total oil production, at 2 mb/d in 2027 and 3 mb/d by 2030.

OPEC+ Africa crude oil production capacity (y-o-y change), 2024-2030



While Nigeria has seen the exit of most major foreign companies from its onshore portfolio, including ExxonMobil's sale of Mobil Producing Nigeria Unlimited to Seplat Energy and Shell's sale of its onshore assets to Renaissance, the government's sweeping reforms have sparked cautious optimism and increased investor interest. ExxonMobil announced plans in May to invest USD 1.5 billion to revitalise production at its flagging Usan deepwater oil field, with a final investment decision (FID) expected in late Q3 2025.

This follows the sanctioning in late 2024 by a Shell-led consortium of the Bonga North development with a capacity of about 110 kb/d, aimed at sustaining production at the Bonga floating production storage and offloading (FPSO) facility, with first oil expected towards the end of the decade. Shell is also reviewing the potential sanctioning of Bonga Southwest (150 kb/d crude and condensate capacity) with an FID expected in 2027. However, in late May TotalEnergies entered into an agreement with Shell to sell its non-operating interest in the Bonga fields, which includes Bonga North and Bonga Southwest, as the companies work their respective strategies to optimise and upgrade their portfolios. Despite Nigeria's expansive new incentive and contract terms, international companies appear to be taking a watchful approach, waiting to see how the implementation and delivery of the reforms are executed.

Libyan total oil output for 2024 was down 90 kb/d y-o-y to 1.1 mb/d following a six-week shut-in of fields during the country's banking crisis in August and September of last year. Well workovers during the shut-in helped to push crude output up to 1.2 mb/d at year-end. With over 90% of Libya's revenues coming from the oil and gas sector, the fields and oil terminals are frequently targeted by political factions.

In March 2025, Libya announced for the first time since 2007 significantly improved production sharing agreement terms for foreign companies, along with a licensing round for 22 exploration areas which so far has attracted over 40 applicants. Contract awards are scheduled for 22-30 November 2025. However, any exploration and development pick up in Libya will fall outside of our forecast period.

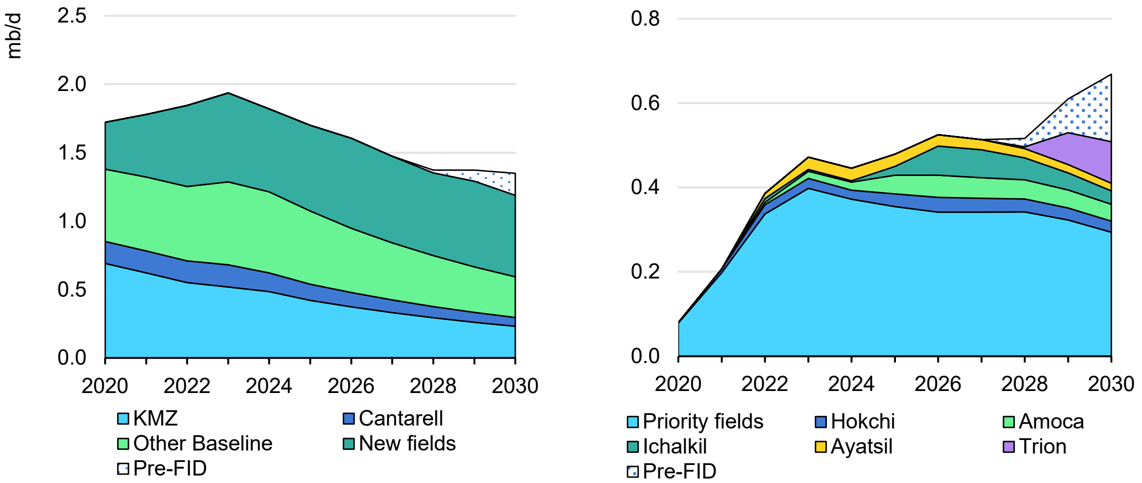
Libyan capacity reaches 1.25 mb/d this year before declining below 1.2 mb/d by 2030. Smaller capacity gains, such as those at the recently restarted Mabruk field, will add about 25 kb/d, following the field's shut-in since 2015. Further near-term gains may come from Akakus (a joint venture of the Libya's NOC, Repsol, TotalEnergies, OMV and Equinor) as it works an ambitious plan to increase capacity at the Sharara field blocks NC-186 and NC-115, from 300 kb/d to 350 kb/d, by the end of 2025.

Mexico risks becoming a net importer as output declines

Mexico posts the largest drop in output, not just among the OPEC+ alliance, but out of all producers globally – falling 680 kb/d to 1.3 mb/d over the forecast period. Paired with this *Report's* demand forecast, this could lead the country to become a net importer of close to 500 kb/d by 2030. Its long-term oil production decline showed a brief respite from 2021-23 as the Quesqui condensate field ramped up in earnest. Pemex severely curtailed planned investments during the pandemic, with the previous administration requesting the state oil company focus on quick crude growth from onshore and shallow-water fields to the detriment of larger deepwater reservoirs. As of 2024, over half of Pemex's production came from just seven of its 240 fields.

Looking forward, challenges remain with Pemex carrying a high debt load and only one major project slated to see first oil by 2030. Output declined by close to 160 kb/d y-o-y in 1H 2025. Fiscal changes, large unpaid debts to its suppliers and upstream budget cuts have seen oil rigs slashed from 50 in October 2024 to fewer than 20 in less than six months – although recently some payments reportedly have been made and five rigs have returned to work. Woodside's 100 kb/d Trion project is still targeting first oil in 2028 while Zama and the Ku-Maloob-Zaap (KMZ) expansion still await sanctioning. Yet the window to see production from these two developments before the end of our forecast is closing.

Mexico total production and growth from new fields, 2020-2030



Non-OPEC+ supply

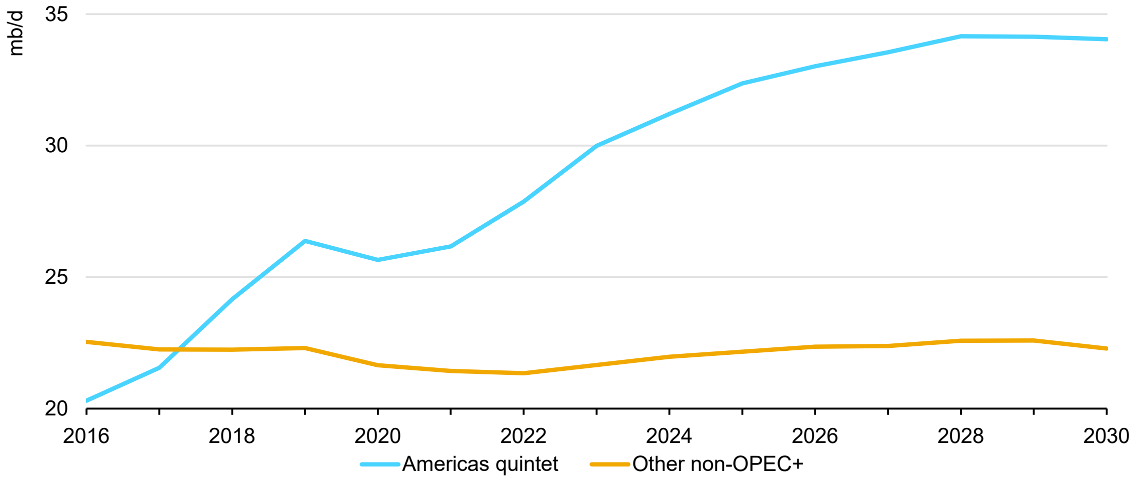
Non-OPEC+ Americas quintet to continue supply growth

The Americas dominates total non-OPEC+ supply increases of 3.1 mb/d through the medium-term, even as the pace of growth slows markedly. Following gains of as much as 11 mb/d since 2016, the quintet – comprised of the United States, Canada, Brazil, Guyana and Argentina – will boost production a further 2.8 mb/d by 2030, with their combined output approaching one-third of global oil supply.

The United States remains the largest single source of non-OPEC+ gains, even as US LTO growth stalls. Canada comes in a close second as expanded pipeline egress helps facilitate bitumen expansions and shale drilling brings incremental NGL volumes.

Guyana, powered by the ExxonMobil-led Stabroek Block, continues to execute its ambitious growth targets, while neighbouring Suriname will see the TotalEnergies-led offshore Block 58 produce its first barrels by the end of the decade. Further south, Brazil continues to ramp up production, albeit at a slower pace than expected previously, with Petrobras and other large oil companies continuing the FPSO factory development of pre-salt reservoirs. Vaca Muerta growth will be boosted by new takeaway capacity and as economic reforms make their way through the Argentinian economy.

Americas quintet has grown while other non-OPEC+ has stayed flat, 2016-2030



Note: Chart includes total oil supply (crude, condensates, NGL, biofuels and non-conventional). Americas quintet includes the United States, Canada, Brazil, Guyana and Argentina. Global biofuel production included in other non-OPEC+.

Total non-OPEC+ supply (mb/d)

	2024	2025	2026	2027	2028	2029	2030	2024-30
OECD	**29.9**	**30.7**	**31.0**	**31.2**	**31.2**	**31.1**	**30.9**	**1.0**
OECD Americas	26.3	27.0	27.3	27.7	27.8	27.8	27.9	**1.6**
OECD Europe	3.2	3.3	3.3	3.1	3.1	2.9	2.7	**-0.5**
OECD Asia Oceania	0.4	0.4	0.4	0.4	0.4	0.4	0.4	**-0.1**
Non-OECD	**17.5**	**17.9**	**18.2**	**18.5**	**19.1**	**19.2**	**18.8**	**1.4**
Eurasia	0.3	0.3	0.3	0.3	0.3	0.3	0.3	**-0.0**
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	**-0.0**
China	4.3	4.4	4.4	4.4	4.3	4.3	4.2	**-0.1**
Other Asia	2.0	2.0	1.9	1.9	1.9	1.9	1.9	**-0.1**
Non-OECD Americas	6.4	6.8	7.2	7.3	7.7	7.8	7.6	**1.2**
Middle East	1.9	1.9	2.0	2.0	2.3	2.4	2.5	**0.6**
Africa	2.4	2.4	2.4	2.5	2.5	2.4	2.3	**-0.1**
Non-OPEC+ Oil	**47.4**	**48.6**	**49.2**	**49.7**	**50.4**	**50.2**	**49.8**	**2.4**
Processing Gains	2.4	2.4	2.5	2.5	2.5	2.5	2.5	**0.1**
Global Biofuels	3.4	3.5	3.7	3.8	3.9	4.0	4.1	**0.7**
Total Non-OPEC+ Supply	**53.2**	**54.5**	**55.4**	**55.9**	**56.7**	**56.7**	**56.3**	**3.1**
Annual Change	*1.5*	*1.4*	*0.8*	*0.6*	*0.8*	*-0.0*	*-0.4*	

Note: OECD Americas excludes Mexico, which is included in OPEC+ data.

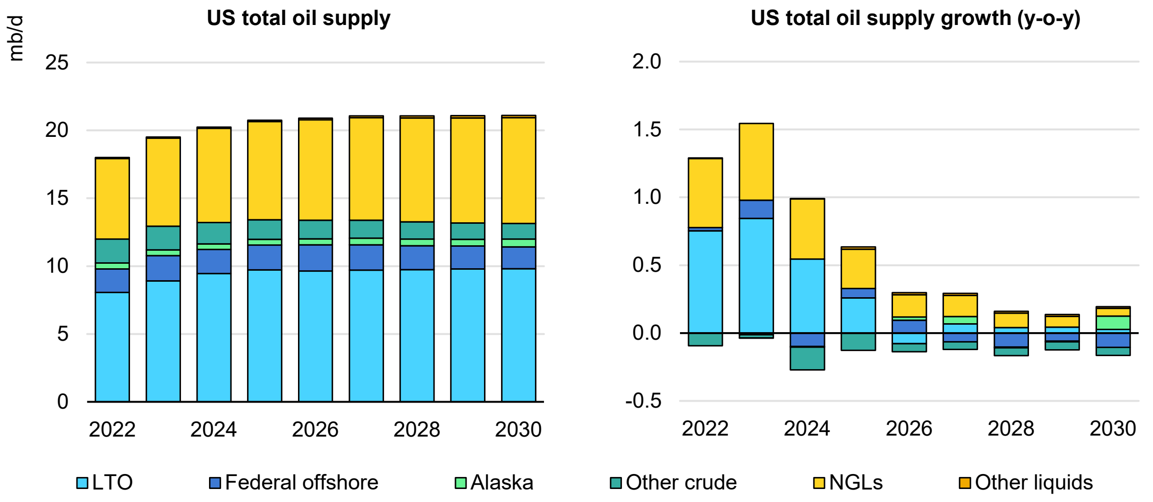
In the Middle East, Qatar is set to notch impressive increases in associated liquids from their North Field East and South LNG expansions. Global biofuels output will grow by 680 kb/d, with non-OECD countries accounting for 75% of the gains. Recent major discoveries in Namibia and Côte d'Ivoire are advancing through the exploration and appraisal lifecycle, while other small West African producers continue to see growth. Angolan output is flat over the forecast period, as new projects offset declines at mature assets. The Lake Albert development in Uganda continues to progress, with first oil scheduled for 2026.

Other non-OPEC+ regions, however, continue to slump. North Sea supplies are set to decline without a robust queue of new projects to be sanctioned. A decade-long downtrend in ex-China Asia Pacific oil supply continues, as companies prioritise natural gas developments. Other legacy South American producers have seen increased political risk hampering an already challenging development outlook.

US shale growth slows precipitously

US liquids output, excluding biofuels, expanded by 720 kb/d in 2024, and by a total 3.7 mb/d since the Covid-19 trough in 2020. Oil supply is expected to rise by a further 510 kb/d in 2025, reaching a fourth consecutive annual record high. While US oil production is set to increase every year through the forecast period, the pace of growth will slow markedly as crude plateaus. Greater shareholder distributions, producer consolidation and increasingly complex wells amid a possible 'lower for longer' price environment act as headwinds to the industry.

US growth expectations moderate over the remainder of the decade, 2022-2030

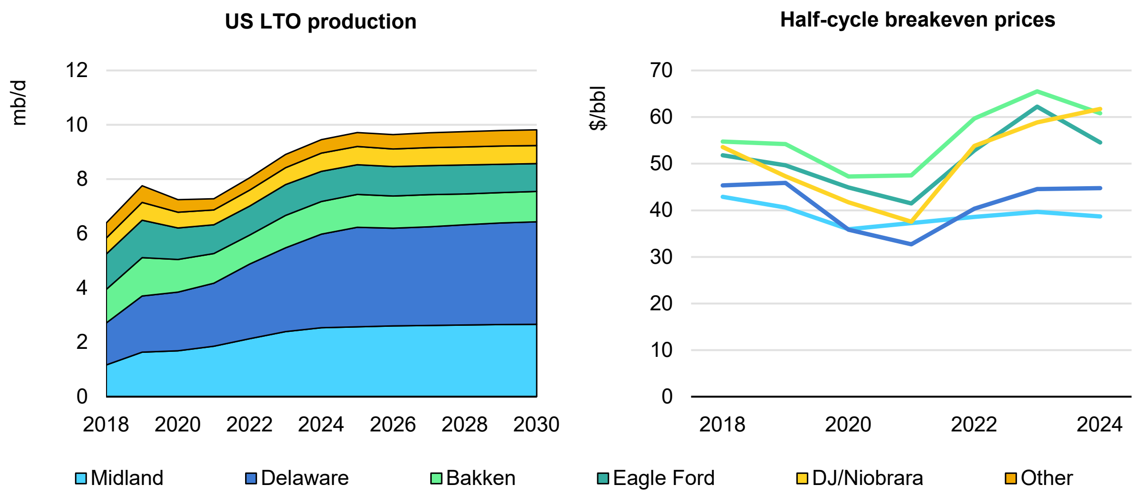


Even then, the United States is the second-largest contributor to medium-term supply capacity growth (behind Saudi Arabia), adding 880 kb/d over the 2024-30 period, to reach 21.1 mb/d by the end of the forecast. Crude oil production is expected to decline by 60 kb/d to 13.1 mb/d. NGLs from processing plants are set to rise by 860 kb/d to 7.8 mb/d, led by both higher exports and domestic petrochemical facility utilisation as associated gas from the Permian and Appalachia Basins continues to drive growth. Non-conventional volumes make up the balance.

US LTO production increases by 360 kb/d from 2024 to 2030, reaching 9.8 mb/d, while conventional Lower 48 supply is expected to decline by 420 kb/d over the same time frame. Federal offshore output is forecast to rise by 160 kb/d between 2024 and 2026 to 1.9 mb/d, before retreating to 1.6 mb/d by 2030. Alaskan volumes are set to increase by 160 kb/d to 580 kb/d by the end of the decade.

While LTO remains the major engine of US oil supply growth, annual gains slow precipitously, with production essentially plateauing in the later years of the decade. Total shale production rises by a modest 0.5% annual average, with the Permian Basin essentially the sole contributor. The reassessment of US shale prospects compared to *Oil 2024* is due to lower prices that have prompted shale producers to scale back activity and industry consolidation. Indeed, data from Enverus show that over 70% of the sub-USD 50/bbl economic Permian Basin locations are operated by seven companies, with ExxonMobil and Diamondback holding over half the remaining locations in the Midland Basin.

Permian Basin drives US LTO growth with the lowest breakeven prices, 2018-2030

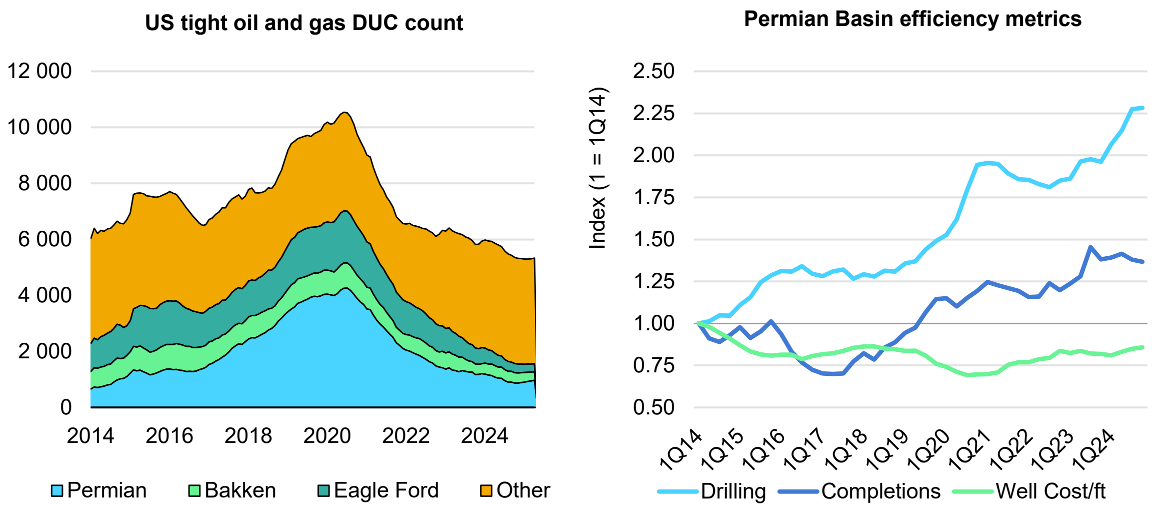


Note: Half-cycle breakeven prices are based on drilling and completion costs net of royalties, production tax, lease operating expenses, transportation costs and differentials, general and administrative charges and corporate tax.
Source: Half-cycle breakeven prices based on IEA analysis of data from Rystad Energy ShaleWellCube.

Additional headwinds stem from low levels of drilled but uncompleted wells (DUCs) within US shale basins. According to data from the Energy Information Administration's Short-Term Outlook (EIA STEO), DUC levels are at the lowest level since the government began tracking in 2013 and have fallen by 15% over the last two years to 5 300 wells, with the industry on pace to complete just shy of 9 000 wells this year. Key oil producing areas such as the Bakken, Eagle Ford and Permian have seen steep DUC drawdowns over the past three years, with the Permian Basin count currently sitting at only one-third of its pre-Covid average.

DUCs can normally be fracked and brought online in two months compared to the 9-12 months it takes to drill and bring on a new well. The continued just-in-time inventory model reduces operational buffers and complicates field development planning and optimisation. Combined with reduced activity, this presents headwinds to growth over the coming years.

US DUCs are at record lows while Permian Basin drillers keep getting better, 2014-2030



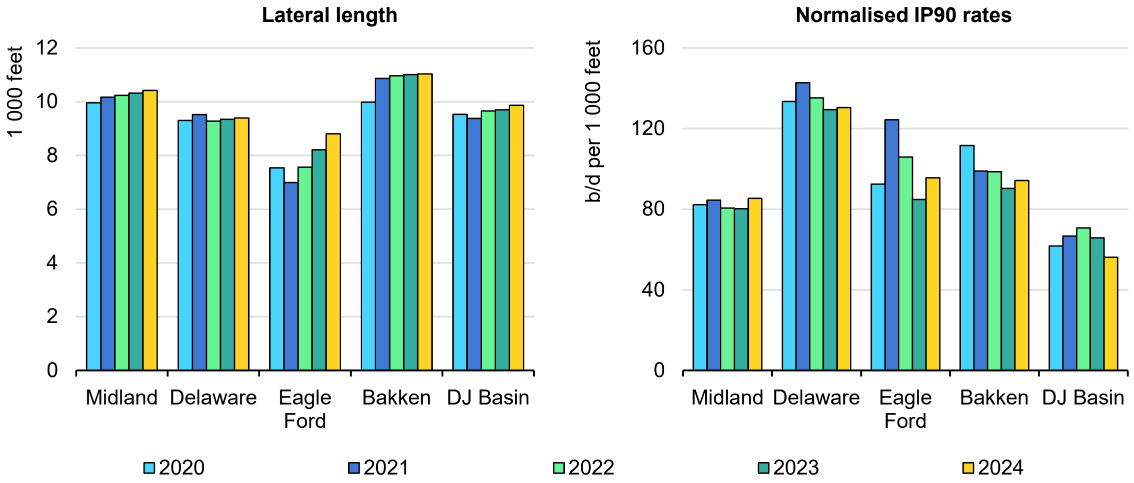
Notes: DUC counts include oil and gas wells drilled in oil and gas formations. Drilling efficiency is the average total measured depth (TMD) for horizontal oil wells in the Permian Basin divided by average drilling days. Completion efficiency is TMD divided by active frac days. Well costs are on a total well basis normalised to TMD.
Source: IEA analysis based on data from the EIA STEO and Rystad Energy's ShaleWellCube.

The high-grading of frack spreads, longer laterals and innovations such as simul-fracs, tri-fracs and horseshoe wells have allowed operators to continue to realise production gains while operating fewer drilling rigs. Since 2014 drillers in the Permian Basin are almost two and a half times more efficient and since 2019 they are over one and a half times more efficient. As a result, the 285 Permian Basin oil rigs that were active in Q4 2024 drilled an equivalent amount to 480 rigs five years ago and 650 rigs ten years ago.

When normalising for lateral length, well costs have begun to creep higher and initial production rates on a 90-day basis have, for the most part, flattened out. We still assume that productivity gains will taper off, although some metrics may show an aggregate improvement as less efficient rigs and frack spreads are sidelined and rig-specific deflationary trends continue.

While decelerating, NGL growth will not slow as sharply as LTO as gas-oil ratios (GOR) have been increasing across key shale basins. US NGL production grows by 860 kb/d from 2024 through 2030. Data from Enterprise Products, an integrated midstream pipeline company and one of the largest NGL handlers in the world, show that every barrel of oil produced in the Permian Basin now has close to 30% more NGLs and natural gas associated with it when compared to 2022.

Productivity trends have tapered in key LTO basins, 2020-2024



Note: Normalised IP90 rates are the median flow rates taken over 90 days then divided by the median lateral length.
Source: IEA analysis based on Rystad Energy ShaleWellCube data.

This is in part due to tight oil reservoir dynamics and the change in relative product mix over time, new drilling locations – including aerial expansions into gassier portions of the basin – as well as development strategies. There is more co-development drilling, where multiple stacked geologic zones – or benches – are developed concurrently leading to production from previously sub-economic zones that may be gassier from the start.

Shale oil price sensitivities

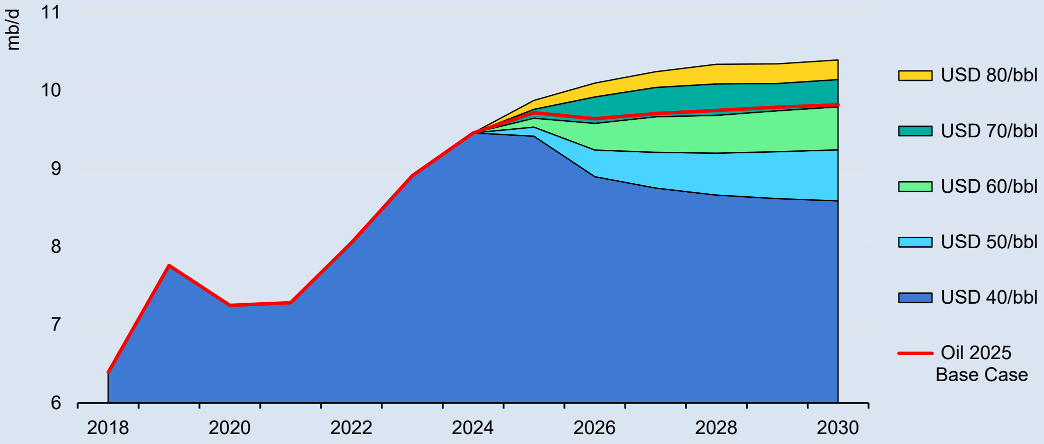
The oil prices used for modelling purposes in this *Report* are based on the NYMEX WTI forward curve in Q2 2025, rising from USD 60/bbl in 2026 to USD 62/bbl in 2030. For 2025, prices are pro-rated between realised WTI prices and the forward curve. These prices are then discounted to real terms. Additionally, some adjustments have been made to account for shale operators that are deemed less price responsive due to corporate planning assumptions, hedging programmes or other factors.

We also take into account changes seen in productivity, cost and DUC levels. Manual adjustments are used sparingly to tie to actual data and account for items such as repeated winter weather related shut ins.

Our modelling suggests that there are approximately 4-5 drilling rigs and 2-3 frack spreads at risk per dollar of sustained price movement between USD 45/bbl and USD 70/bbl. At higher price levels, recent behaviour suggests that additional cash flow from operations does not get reinvested at the same rate.

Base case LTO growth over the medium-term is expected to be 360 kb/d and, while sustained higher prices would drive increased activity levels and extra barrels, the production ceiling is lower than previous analysis showed. Should prices retreat further and stay below the threshold for drilling new wells, producers are expected to announce more activity cuts. It is estimated that a USD 80/bbl flat real WTI price would result in an additional 580 kb/d of growth by 2030 while USD 40/bbl flat real sustained WTI would see 1.2 mb/d of losses compared to the base case by 2030.

US LTO production at different flat real WTI price levels, 2018-2030



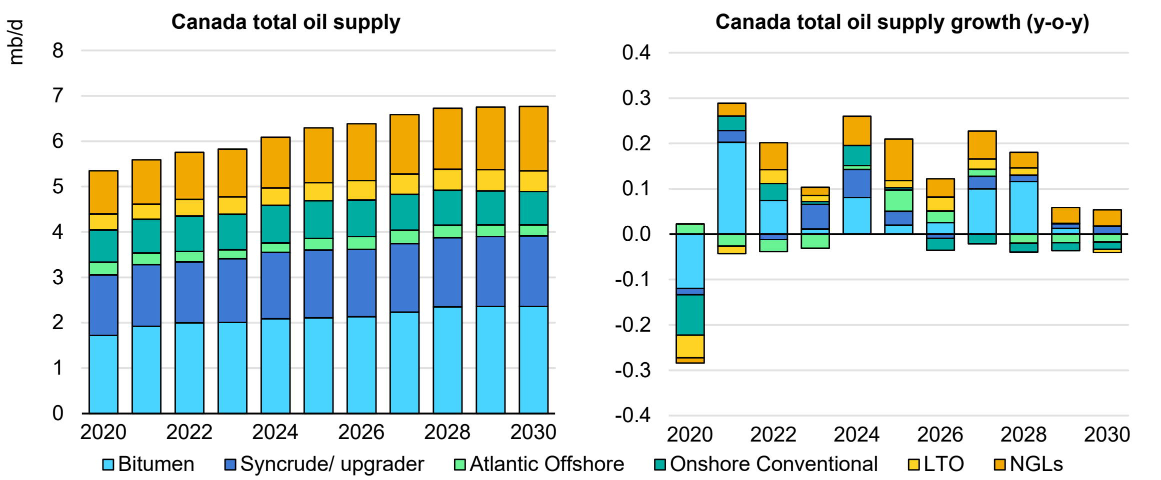
After rising by 160 kb/d to 1.9 mb/d in 2026, US federal offshore production is expected to fall to 1.6 mb/d by 2030, 170 kb/d below current levels. Following the start-up of 280 kb/d of new capacity in 2025, only 260 kb/d of additional capacity is sanctioned to come online from 2026 to 2030 – including Beacon Energy's Shenandoah Phase 2, BP's Kaskida and Shell's Vito infill and Sparta projects. An additional 400 kb/d of pre-FID developments could come online by the end of the decade if sanctioning decisions are made over the next two years.

Two Alaskan projects with 230 kb/d of capacity are also slated to see first oil during the latter half of the decade. The 80 kb/d Santos-operated Pikka Phase 1 development, and the 150 kb/d ConocoPhillips Willow project are expected to start in 2026 and 2029, respectively. Alaskan output will increase by 35% to 580 kb/d as these fields start up.

Discounts and debottlenecking of Canadian crude

Canadian production is set to continue its upward trajectory over the forecast period, buoyed by increases in bitumen and NGL output. The Western Canada Sedimentary Basin (WCSB) will account for most of the growth through the end of the decade, bringing total liquids to 6.8 mb/d. Out of the 680 kb/d total increase, 270 kb/d will be bitumen and 300 kb/d NGL.

Canadian oil supply and annual changes, 2020-2030

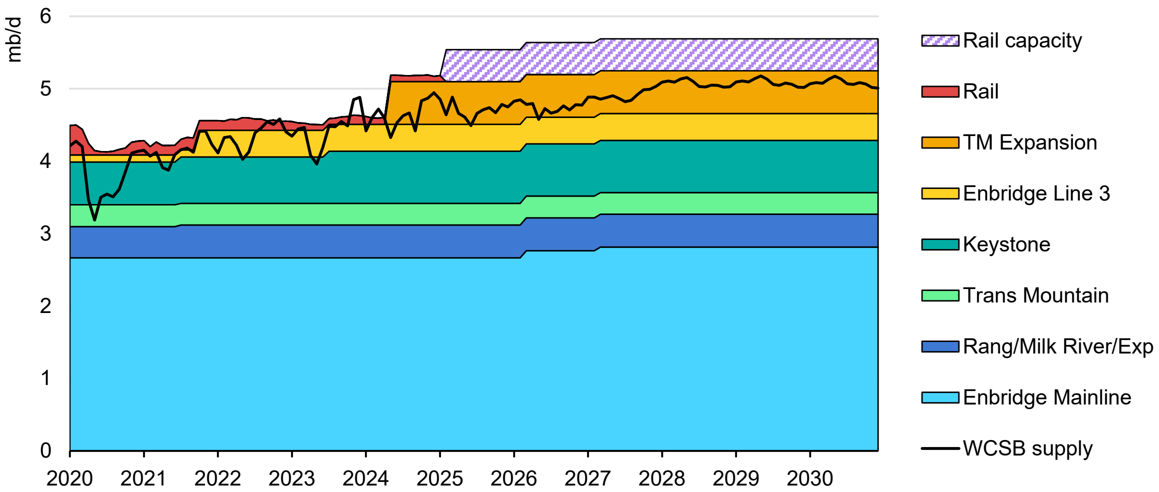


Bitumen supply rises to 2.4 mb/d in 2030, driven by optimisation and debottlenecking of operations at oil sands projects, while new capital projects and expansions are limited in size and scope. NGL growth will come from associated liquids as LTO and shale gas developments continue across the Montney, Duvernay and Cardium plays. Total NGL output, including pentane plus, will top 1.4 mb/d by 2030 while LTO increases by 80 kb/d to 460 kb/d.

Canadian offshore output will finish the decade 30 kb/d higher at 240 kb/d after peaking in 2027 at 300 kb/d as Cenovus brings on its 50 kb/d West White Rose project. Exploration interest is muted with Equinor, the only company to have recently drilled a successful exploration well in the area, putting any field development on hold.

Takeaway capacity for the WCSB was expanded by 590 kb/d when the Trans Mountain Expansion (TMX) pipeline entered into service in Q2 2024, offering some relief to producers by increasing egress options and tightening local price differentials relative to WTI. Based on data from *Argus Media*, Western Canadian Select (WCS) Hardisty crude traded at a USD 12.60/bbl discount on average for the twelve months since TMX came into service compared to negative USD 17.20/bbl for the year prior.

Western Canada Sedimentary Basin liquids takeaway capacity, 2020-2030



Notes: Western Canada Sedimentary Basin (WCSB) supply includes a 35% diluent ratio for non-upgraded bitumen and is net of 550 kb/d of non-export refining capacity. Nameplate pipeline capacity assumed, does not account for changes in available capacity due to maintenance or other items. Enbridge Mainline optimisation phase 1 included.

Source: IEA analysis based on data from the Canadian Energy Regulator, Enverus and company statements.

The Latin America FPSO factory shows signs of slowing

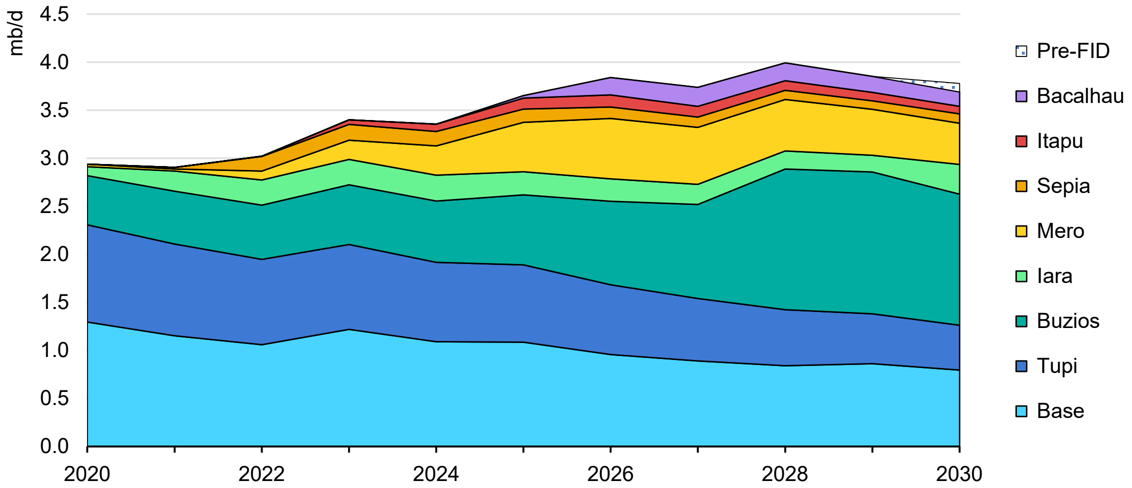
Total non-OPEC+ Latin American oil supply will grow by 1.2 mb/d to 7.6 mb/d in 2030, after peaking at 7.8 mb/d in 2029. Growth will continue to be driven by developments in Brazil's offshore pre-salt, Guyana's Stabroek Block and Argentina's Neuquén Basin. These resources, along with Block 58 in Suriname, will more than offset declines from mature fields in the region. Additional barrels could come online if further projects are sanctioned in Guyana and Brazil's pre-salt, while just over the horizon are frontier areas such as Brazil's Equatorial Margin or Argentina's North Argentine Basin.

Brazilian output is on track to increase by 640 kb/d from 2024 to 2028 when it reaches 4.1 mb/d before retreating to 3.8 mb/d in 2030 in the absence of additional project start-ups. Petrobras operated fields are expected to contribute most of the gains, while TotalEnergies, Shell, Equinor, China National Offshore Oil Company (CNOOC) and CNPC also expand their footprint in Brazil's prolific offshore. The Santos Basin, home to 70% of the country's current crude production, will continue to lead the expansion. Yet persistent project delays, operational issues and a tightening of maintenance spend could put Brazil's projected growth at risk.

Last year saw operational issues and labour action by a regulatory body impact 300 kb/d of output, while Petrobras' updated strategic plan pushed back six FPSO start dates. Along with a reduction in maintenance spend in response to lower oil prices, 2030 Brazilian oil production has been reduced by 500 kb/d compared to *Oil 2024*.

That is not to discount the monumental FPSO factory development plan that is mid-flight within Brazil. The Mero and Búzios fields will deploy a total of 15 FPSOs by 2028, including nine already in service. Petrobras plans to bring online eight FPSOs between now and 2030, including five additional Búzios installations. Once completed, the 11 Búzios FPSOs will have capacity of close to 2 mb/d. There are only two pre-FID projects that may see first oil by 2030 – Equinor's 100 kb/d Bacalhau Phase 2 and Petrobras's 100 kb/d BRC/CRT revitalisation.

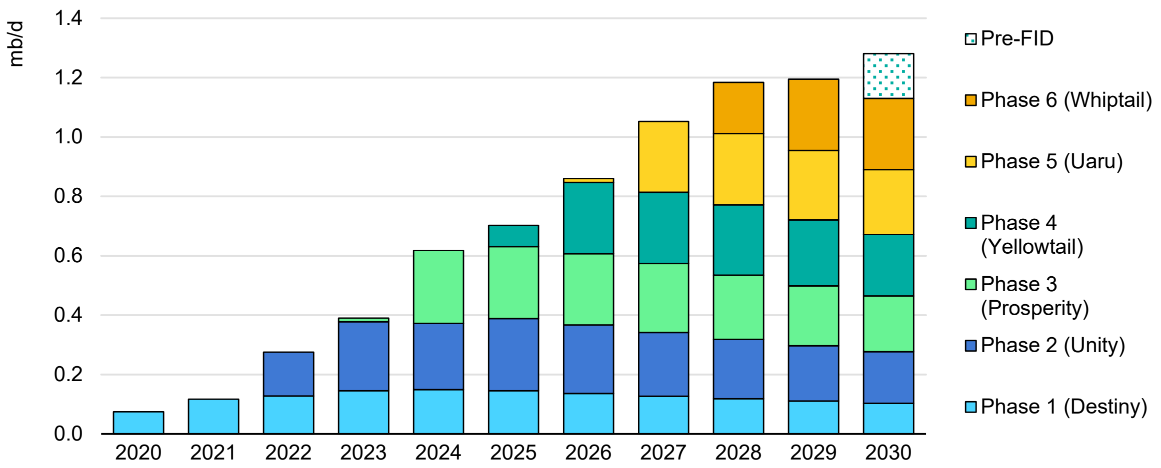
Delays and declines weigh on future Brazilian growth, 2020-2030



The ExxonMobil-led consortium made further discoveries in **Guyana's** prolific Stabroek Block in 2024. Current estimates of recoverable oil equivalent resources are close to 12 billion barrels and a seventh development phase is scheduled to be sanctioned later this year. An eighth phase is slated to be approved in 2027. Based on the current sanctioned project pipeline, and in the absence of accelerated schedules, production should reach 1.2 mb/d in 2029 – double the 600 kb/d of supply in 2024.

Suriname's first offshore barrels will come from TotalEnergies and APA Corporation's recently sanctioned Block 58 development. The parcel sits adjacent to Guyana's Stabroek Block and the 220 kb/d FPSO is expected to produce first oil in 2028, bringing the country's output from 20 kb/d of onshore production in 2025 to 220 kb/d at the end of the decade. Three other blocks in the country look promising, but even if exploration results yield commercial resources, those volumes would likely only materialise in the second half of the next decade.

Guyana growth driven by phased development of the Stabroek Block, 2020-2030



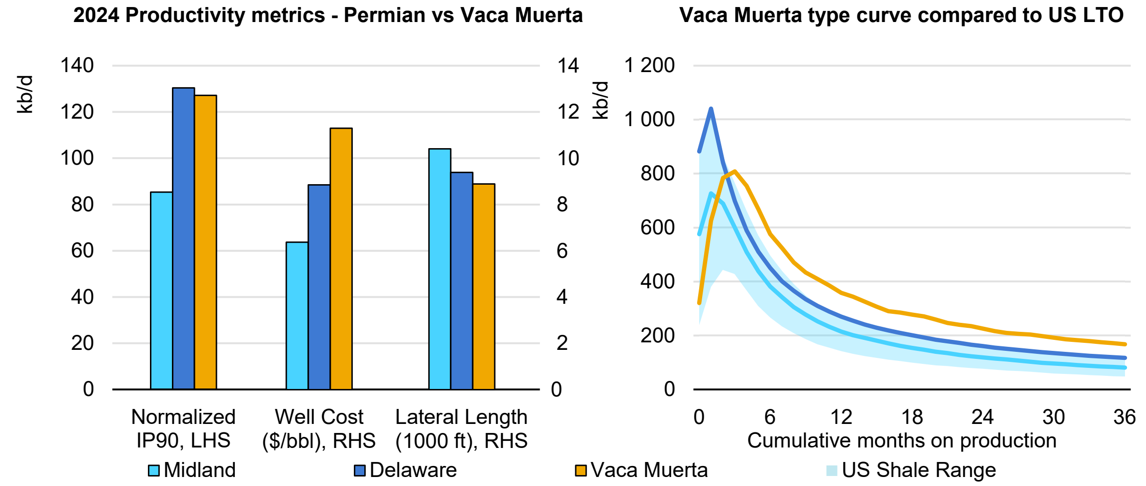
Argentina's supply is forecast to grow by 430 kb/d to 1.3 mb/d through 2030 as its main shale patch the Vaca Muerta in the Neuquén Basin roars ahead. LTO is projected to rise by 500 kb/d, to just shy of 900 kb/d, while conventional supplies decline to 230 kb/d. New takeaway capacity, robust drilling and fracking activity as well as economic reforms underpin the LTO growth story in Argentina.

On 14 April 2025, President Javier Milei removed most capital and currency controls, alleviating international companies' concerns that profits would be trapped in Argentina. This continues the path of sectoral reforms along with the Régimen de Incentivo para Grandes Inversiones (RIGI) law passed last autumn which will provide 30 years of legal and regulatory stability in addition to tax breaks and export exemptions for projects greater than USD 1 billion.

Additional takeaway capacity is under construction, with the first phase of the 440 km Vaca Muerta Sur pipeline expected to enter service by the end of 2026. The 700 kb/d pipeline will bring LTO barrels for export to Punta Colorada in the Rio Negro state. The first phase will have capacity for 180 kb/d. The following year sees the project expand to 550 kb/d, with full capacity targeted for 2028.

The reforms and pipeline build-out help to unlock Vaca Muerta production. The play has high quality unconventional reservoirs that also benefit from a decade of derisking and operational learnings from North America. Indeed, the normalised initial 90-day average oil production (IP90) competes with the Delaware sub-basin within the Permian and outperforms the Midland sub-basin. While lateral lengths are still shorter than in the Permian, there remains upside in reducing well costs.

Argentina's LTO well productivity competes with the Permian, costs have room to fall



Notes: In the lefthand chart values are for the median well. In the right-hand chart, average type-curves are for the 2022-2024 drilling programme. Includes oil only and key US basins (Permian, Eagle Ford, Bakken and DJ-Niobrara). Actual and forecast data included.
Source: IEA analysis of data from Rystad ShaleWellCube.

By contrast, supply in the rest of Latin America is expected to decline due to a lack of investment and new projects. **Peru**, currently producing 120 kb/d of crude and NGLs, announced plans to boost upstream investment over the next five years. This has already begun to mitigate losses, but the roadmap to increased volumes remains unclear.

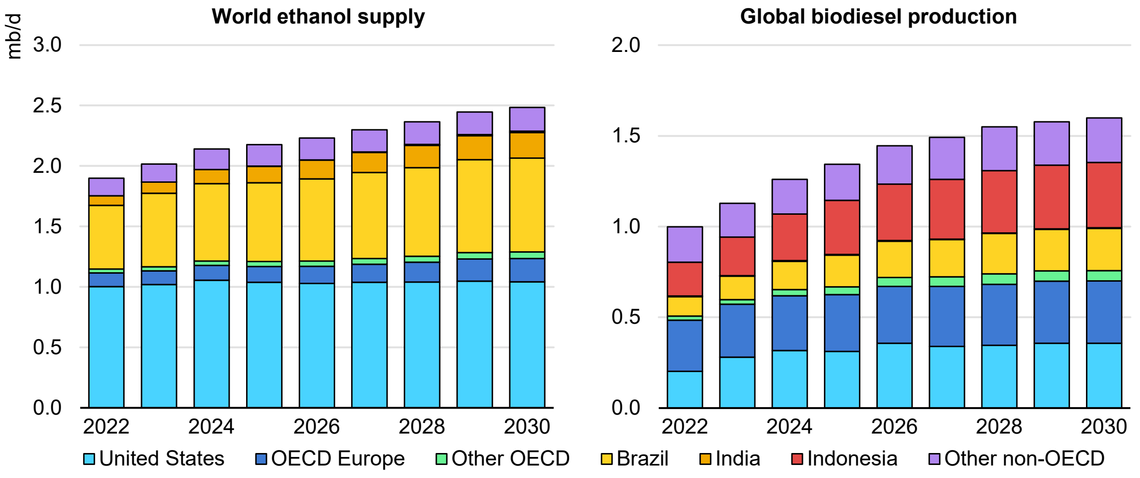
Ecuador and Colombia have seen reduced oil and gas investment levels in recent years as their governments have prioritised clean energy developments. In **Ecuador**, the passing of a 2023 referendum to close the 60 kb/d Ishpingo-Tambococha-Tiputini (ITT) field has been scaled back to ban new activity but allow existing wells to produce. More recently, optimism around renewed private investment dimmed as Sinopec missed the deadline to acquire the right to operate the 80 kb/d Sacha field. This *Report* forecasts output to fall 110 kb/d to 370 kb/d by 2030.

After the 2022 elections, the **Colombian** government halted new oil and gas exploration licenses and completely banned hydraulic fracturing (fracking) in tight oil and gas reservoirs. While mature oilfields have seen improved maintenance operations that have lessened underlying decline rates, output is still projected to fall from 790 kb/d in 2024 to 630 kb/d at the end of the decade.

Biofuels growth driven by developing and emerging countries

Global biofuels growth of 680 kb/d, split equally between ethanol and biodiesel is expected from 2024-30. Brazil and India lead ethanol production growth, adding 140 kb/d and 100 kb/d, respectively, and account for 70% of the total increase. Biodiesel gains are more geographically dispersed with Indonesia and Brazil forecast to deliver the largest contributions of 100 kb/d and 80 kb/d, respectively, through the end of the decade. The United States will add an additional 40 kb/d and Canada 20 kb/d.

Global biofuel supply split by ethanol and biodiesel, 2022-2030



Notes: Biodiesel production includes renewable diesel and other distillate fuels such as biojet and renewable heating oil.

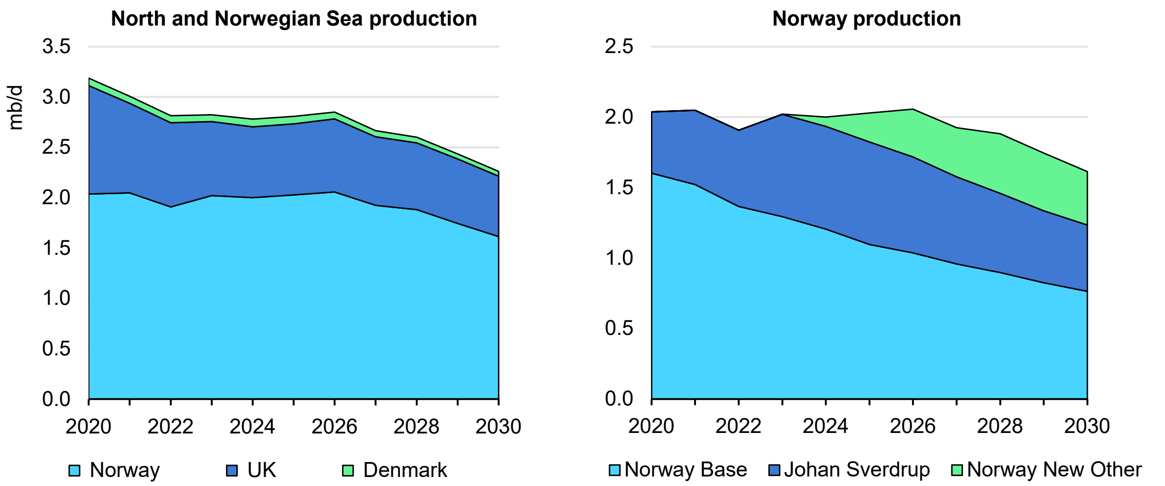
Brazilian growth, representing one-quarter of global increase, comes on the heels of its “Fuel of the Future” programme, which aims to increase domestic biofuel supply and develop a regulatory framework for sustainable aviation fuels (SAF), biomethane and biorefining. A decision to raise gasoline blending requirements to 30% from 27.5% could come as early as 1 July 2025 at the next National Energy Policy Council (CNPE) meeting, while the government plans to gradually increase biodiesel blending annually, aiming to reach 20% by 2030.

North Sea oil in regulatory and political focus

Net-zero ambitions as well as social pressure on governments, major financial institutions and insurers are shaping the production profile of the North Sea. Regional assets are already undergoing a structural shift as private equity and joint venture corporate spin-offs change the operating environment. Fortunes diverge between the United Kingdom and Norway, as the former continues to operate in harvest mode, while the latter has seen more project approvals and field developments in recent years.

The **United Kingdom**'s five-year production decline is expected to pause in 2025 at 710 kb/d before continuing its downward trend through our forecast period. Neptune's 2023 Seagull project, Shell's recent Penguins redevelopment along with BP's Clair Ridge project arrested declines last year and are expected to support supply this year as well. However, these developments, along with Equinor's 2028 Rosebank start-up – pushed back a year to account for the court ruling that more time is needed to assess its impact on the climate – are not sufficient to offset years of weak investment. Despite a few other smaller developments, output is set to reach a 50-year low of 600 kb/d by 2030.

Norwegian investments delay North Sea declines, 2020-2030



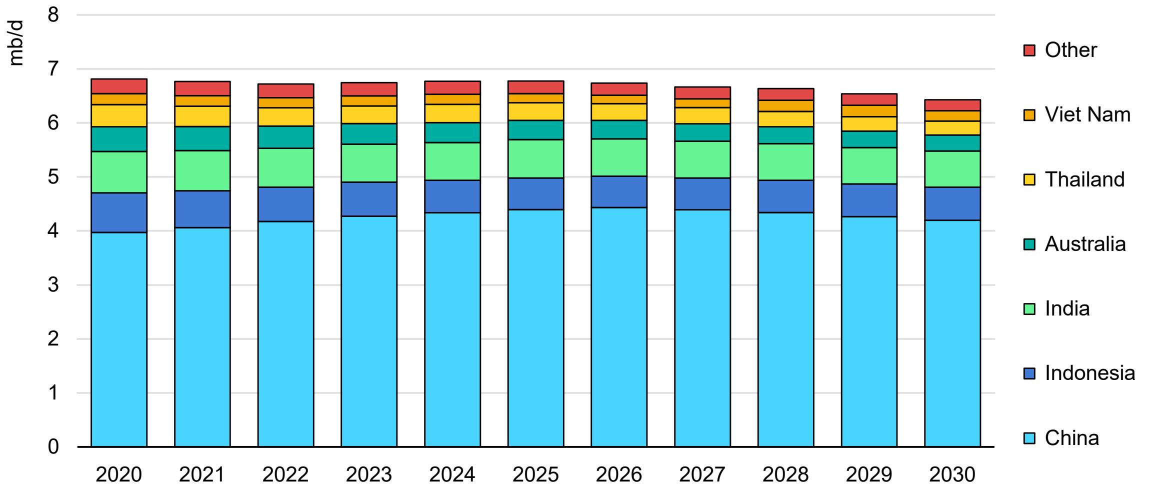
Norway's crude oil production is expected to average 2.1 mb/d this year and next, underpinned by the large Johan Sverdrup project and the recently started-up Johan Castberg field. While a 2024 court ruling invalidated three field licences, producers are moving forward with confidence that the legal challenges will not impede production. Norway has substantial remaining resources, robust infrastructure and low-carbon intensity for oil production. Yet, without the sanctioning of new projects, output will fall to 1.6 mb/d by the end of the decade.

Chinese barrels support a sagging Asia Pacific region

Non-OPEC+ Asia Pacific oil supply has fallen by 650 kb/d over the last decade and is poised to drop by another 340 kb/d to 6.4 mb/d by 2030. While the region has struggled with ageing oil fields, changing ownership structures and investments increasingly geared towards natural gas, signs of change are emerging with significant reforms under way in Indonesia and India.

China has been the exception, thanks to high reinvestment rates, exploration successes and a strong government mandate to increase output. The three state-owned Chinese oil companies – Sinopec, CNPC and CNOOC – have increased investments to stymie declines, raising production by 500 kb/d from the 2018 low of 3.8 mb/d to 4.3 mb/d in 2024. Recent, successive Chinese government Five-Year Plans' have laid out ambitious energy and climate goals that prioritise energy security and fossil fuel developments. The 15th Five-Year Plan, covering 2026-2030 looks to sustain annual oil production above 4 mb/d. Indeed, this Report sees continued offshore projects and onshore infill and delineation drilling efforts boosting total oil supply to a three-year plateau at 4.4 mb/d, before ending the decade at 4.2 mb/d.

Non-OPEC+ Asia oil supply slips through the decade, 2020-2030.



Notes: Chart includes total oil production (crude, condensates, NGLs and non-conventional) from OECD and non-OECD Asia for countries that are not members of OPEC+. Other includes Bangladesh, East Timor, Mongolia, Myanmar, Nepal, New Zealand, Japan, Korea, Israel[1], Pakistan, Papua New Guinea and the Philippines.

Australian supply is forecast to fall from 370 kb/d to 300 kb/d in 2030, driven by declines in the Carnarvon Basin. Santos' 80 kb/d Dorado development was the most promising source of new production for Australia, yet the company recently deferred the project until after further evaluation of Bedout Basin resources has been completed.

[1] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Indonesian oil production, currently at 590 kb/d, is expected to rise modestly to 620 kb/d by the end of the decade. This comes after a series of fiscal reforms, including increased producer revenue sharing to 75-95%, compared to the previous scheme where operators could, at times, receive zero revenue. These reforms, as well as expedited timelines for exploration wells and enhanced oil recovery (EOR) optimisation along with new commitments by Petronas, Eni and PetroChina all support production growth with upside potential over the medium term to this *Report's* forecast.

India also reformed its fiscal terms and held its tenth round of the Open Acreage Licensing Policy (OALP X). The new fiscal terms seek to modernise the upstream regulatory framework, ensuring greater stability and predictability. The windfall tax was removed, and early production fiscal incentives were introduced, while the act was broadened to include light tight oil and shale gas under the regulatory framework.

New tie-ups between Indian state-owned firms and western companies have provided tailwinds for the recent optimism felt in the sector. Examples include Oil India Ltd signing deals with both Petrobras and TotalEnergies, and state-owned Oil and Natural Gas Corporation Ltd (ONGC) agreeing to use a BP subsidiary for technical services. Indian production is expected decline marginally by 30 kb/d to 670 kb/d by the end of the decade.

Qatari oil supply gained 40 kb/d last year to reach 1.8 mb/d. Output is set to rise by 610 kb/d from 2024 to 2030, largely from associated condensates produced from Qatargas's four new LNG trains at North Field East (NFE) and two new trains at the North Field South (NFS) LNG expansion. The six new LNG trains are anticipated to bring on a total of 370 kb/d of condensate and additional associated NGLs online, starting with the first two NFE trains in mid-2026. Qatar's crude production is expected to edge up to 650 kb/d by 2030, from around 620 kb/d currently, largely due to works to lift output from the Al Shaheen field by North Oil Company, a joint venture between TotalEnergies and QatarEnergy.

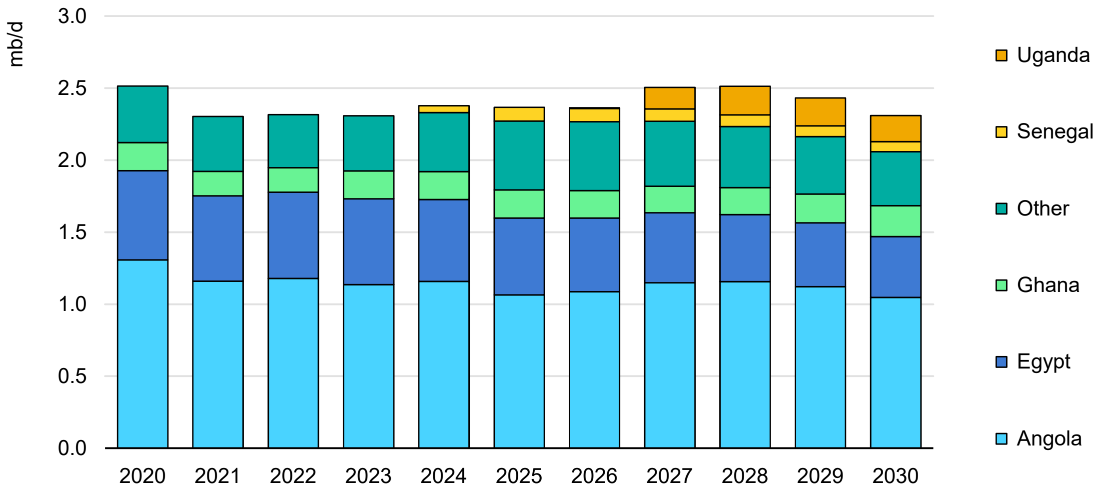
Cautious development in Africa

Non-OPEC+ African supply remains at the crossroads of resource availability and geopolitical risk. In Niger, the recently built pipeline to export additional production has been subject to terrorist attacks and cross-border arrests of high-level officials, resulting in low operating efficiency. Namibia's ruling party has proposed sectoral changes but there is ambiguity regarding their retroactive application to existing contracts. Meanwhile, Angola has pushed through contractual reforms to increase investment, expected to boost supply over the decade. Senegal and Côte d'Ivoire offer stable regimes as companies debate sanctioning more projects in their waters.

Overall, non-OPEC+ African production is forecast to remain relatively flat, falling by 70 kb/d, from 2.4 mb/d in 2024 to 2.3 mb/d by 2030. Despite over 600 kb/d of new capacity coming online, primarily split between Angola and Uganda, field declines continue to outweigh producers' best efforts at growing output. Additional supplies could come from the 580 kb/d of capacity that has not yet been sanctioned, providing some upside potential.

Angolan oil production has been declining for the better part of a decade as the country wrestles with mature fields and ageing infrastructure. After leaving OPEC in 2024, revamped fiscal terms have attracted renewed investments by different majors. Indeed, from 2019-24, 180 kb/d of new capacity was added in the country while 250 kb/d of sanctioned new capacity is forecast to come online through 2030 and another 100 kb/d is awaiting FID. Yet as one of Africa's largest offshore producers, these commitments are just enough to offset declines at existing fields through the decade. Production is set to increase by 100 kb/d through 2028, before returning to the current output of 1.1 mb/d in 2030.

Non-OPEC+ Africa total oil production is stable over the medium term, 2020-2030



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Notes: Chart includes total oil production (crude, condensates, NGLs and non-conventional) from countries that are not members of OPEC+. Other includes Cameroon, Chad, Côte d'Ivoire, Democratic Republic of Congo, Mauritania, Mozambique, Niger, South Africa and Tunisia.

Namibia's Orange Basin has succumbed to geologic realities over the last year as some recent exploration wells have come up dry. Additional uncertainty entered the country's nascent oil and gas sector after recently elected president Netumbo Nandi-Ndaitwah placed the industry directly under her purview, ostensibly to streamline and speed up the permitting and development process.

The ruling party has also proposed increasing state carried interest in all developments. Two promising discoveries, the TotalEnergies-led Venus and the Galp-led Mopane, are in different phases of development, with TotalEnergies slated to take FID next year while Galp is still looking for partners and working on a development plan. If both projects are developed, combined they could potentially produce around 250-400 kb/d sometime in the mid-2030s.

Elsewhere in West Africa, **Senegalese** volumes decline as Woodside is waiting to take FID on Sangomar Phase 2 following last year's 100 kb/d Sangomar FPSO start-up. Likewise, **Niger** supply declines from current levels without sustained infill drilling and delineation work in the Agadem Rift Basin. **Ghana**, on the other hand, sees a continued 20 kb/d uptick in production as drilling programmes there support offshore fields. Eni's success in **Côte d'Ivoire** has revitalised the country's oil and gas sector, leading to expected record in output in 2025. The company is looking to take FID on Baleine Phase 3 this year or next, which would add 100 kb/d, yet it is not included in our forecast. Additional, longer-term tailwinds come from their potential billion-barrel Calao discovery, still in the appraisal phase.

Uganda is set to see first oil in late 2026 from the two Lake Albert projects that TotalEnergies and CNOOC approved in 2021 and 2022, respectively. The developments have been marred by financing issues and environmental controversy as the crude will travel via a 1 440 km heated pipeline to the coast for export. Together, the Tilenga and Kingfisher fields have 200 kb/d of capacity.

Refining and trade

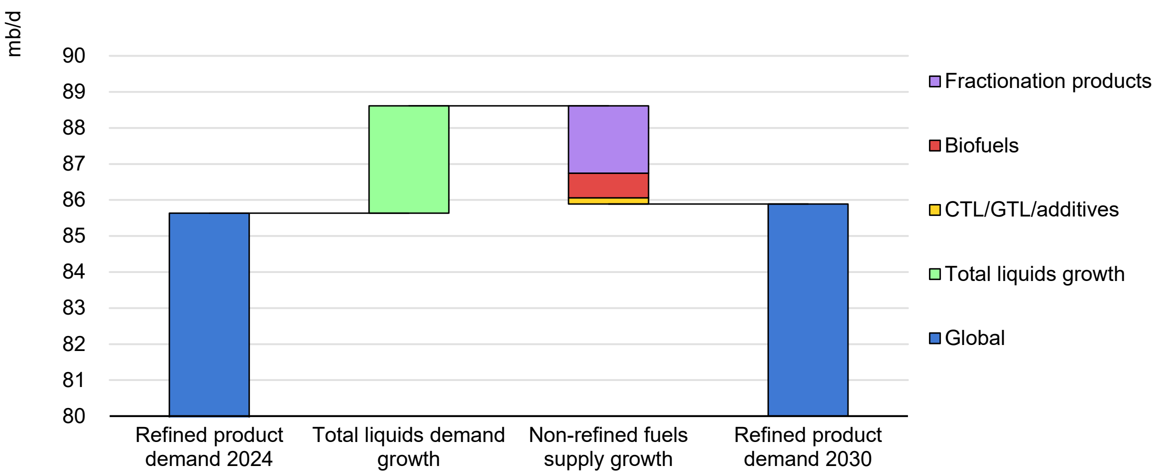
Global summary

Mounting challenges ahead for refining

The refining industry will be increasingly challenged by global oil demand growth underpinned almost exclusively by petrochemical feedstocks produced from non-refined products such as natural gas liquids (NGLs). Limited demand growth for refined products will be led by jet fuel and naphtha while gasoline and diesel post outright declines. This contrasts sharply with continued strong increases in biofuel supplies and NGLs, marginalising the role of refineries in meeting petrochemical feedstock demand.

For refiners, this implies a stark divergence from the long-term trend of rising transport fuel demand that has underpinned the industry's investment strategy and profitability for much of the past 50 years. Adapting to these shifting supply and demand dynamics presents several problems for the industry, but many refiners are already deftly navigating the evolving changes. These emerging trends are brought clearly into focus by our 2024-30 forecast.

Refined products demand growth, 2024-2030



Notes: CTL = coal-to-liquids and GTL = gas-to-liquids. Refined product demand is net of CTL/GTL, NGLs, additives, biofuels and direct use of crude.

Refined products demand is projected to peak in 2027 at 86.3 mb/d, only 710 kb/d above 2024 levels. Thereafter, accelerating declines for gasoline and diesel consumption more than offset growth in naphtha and jet fuel. Concurrent increases in NGLs and biofuels add further pressure to the demand for refined products, reducing it to 85.9 mb/d by 2030 for a net cumulative gain of just 250 kb/d over the outlook period.

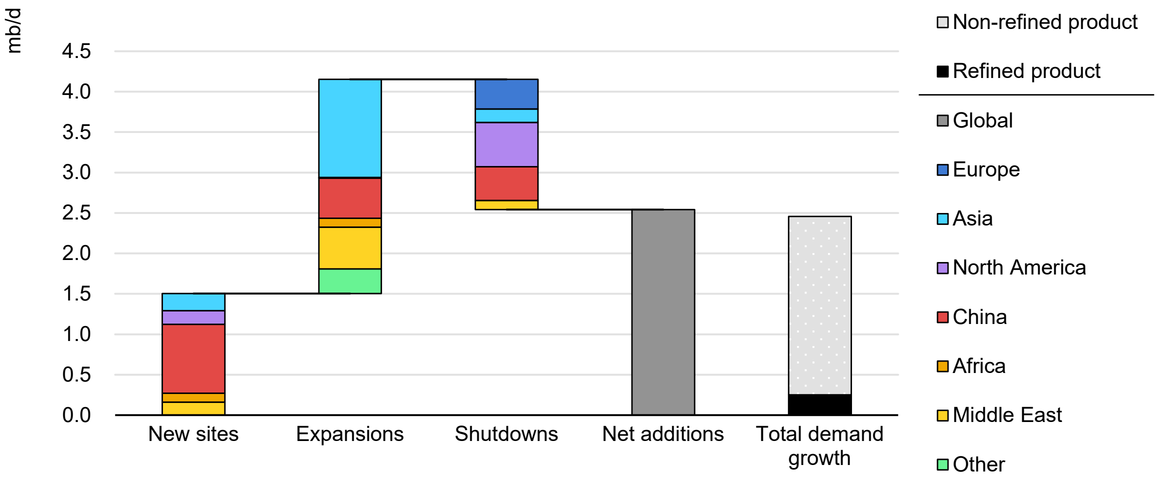
Oil demand and call on refined products (mb/d), 2024-2030

	2024	2025	2026	2027	2028	2029	2030	2024-30 growth
Total liquids demand	103.0	103.8	104.5	105.1	105.4	105.6	105.5	2.5
Biofuels	3.4	3.5	3.7	3.8	3.9	4.0	4.1	0.7
Total Oil demand	99.6	100.3	100.8	101.4	101.5	101.5	101.4	1.8
CTL/GTL*/additives	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.2
Direct use of crude oil	1.0	1.0	0.9	0.8	0.7	0.6	0.5	-0.5
Total call on oil products	97.9	98.4	99.1	99.7	99.9	100.1	100.0	2.1
Fractionation products**	12.2	12.6	12.9	13.4	13.7	13.9	14.1	1.9
Refined product demand	85.6	85.8	86.2	86.3	86.2	86.1	85.9	0.3
Refinery market share	83.1%	82.7%	82.5%	82.1%	81.8%	81.6%	81.4%	-1.7%

Notes: *CTL = coal-to-liquids and GTL = gas-to-liquids. **Ethane, LPG and pentanes plus, excluding estimated diluent use in North America.

Despite weak demand projections, 4.2 mb/d of new refining capacity is expected by 2030, partly offset by 1.6 mb/d of closures. Net capacity growth, driven by Asia – especially China and India – will exceed demand, outpacing shutdowns in Europe and the United States. To restore balance, utilisation rates must drop, or closures must accelerate beyond historical levels. Both factors will reshape the global refining industry, with reductions dictated by refinery competitiveness. High-cost regions like Europe and the US West Coast are most likely to see further cuts.

Refinery expansion and closures and demand growth, 2024-2030



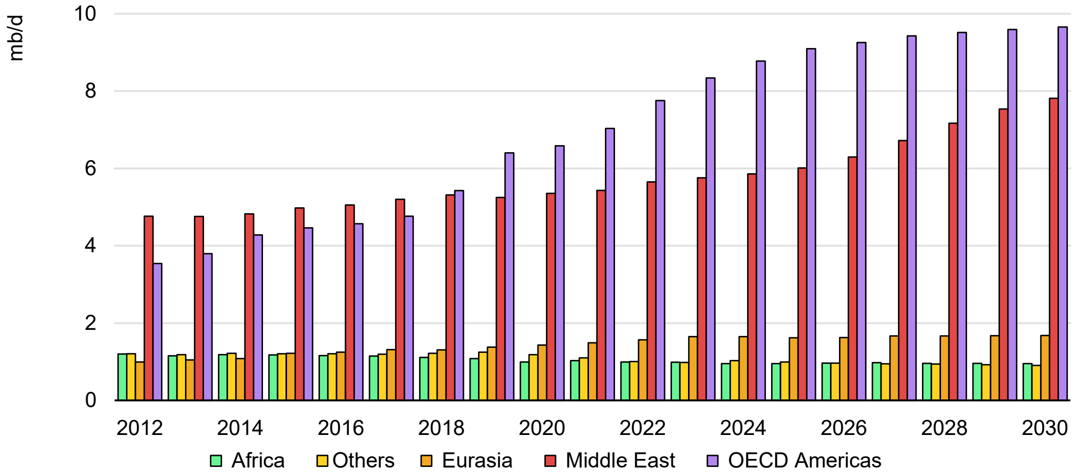
Note: Refined product demand net of CTL/GTL, additives, biofuels, NGLs and direct use of crude.

Shale revolution has upended crude and refining markets

The stellar rise of shale oil and NGLs production from the United States has been the defining characteristic of crude and refining markets since the Global Financial Crisis (GFC) in 2008. The addition of nearly 10 mb/d of light tight oil (LTO) over the last 15 years has redrawn global crude flows and challenged OPEC member states to restrict supplies to support crude pricing. Consequently, shale oil competition has limited the availability of heavy sour Middle Eastern crude grades and thereby compressed upgrading spreads. This shift has provided relatively unsophisticated refineries with a lifeline of cheap, low-sulphur crude that yields a high proportion of light and middle distillates and blend stocks for very low sulphur fuel oil (VLSFO) production. By 2030, US shale oil output growth is forecast to slow to a crawl, with increased Canadian, Brazilian and Guyanese production expected to flip the marginal barrel back closer to the longer-term trend of medium sweet or sour crudes.

However, burgeoning NGLs output, mainly from the United States, has marginalised the role of refineries in meeting petrochemical feedstock demand. Prior to the shale revolution, refinery-supplied naphtha was the dominant source, accounting for 57% of all petrochemical feedstock in 2010. By 2024, this share had slipped to 45%, with ex-refinery naphtha intake largely unchanged in absolute terms over the past 15 years, despite robust growth in petrochemical production. NGLs growth is forecast to remain strong through 2030, adding 1.9 mb/d, split equally between North America and the Middle East.

Regional NGL fractionation supply, 2012-2030



Note: NGL fractionation volumes net of upstream blending requirements.

On balance, prospects for the refining industry for the 2025-30 period are broadly unchanged from last year's Report. In part, this is due to higher NGLs production for both the baseline and future growth, even though we have increased our assessment of the share used as upstream diluent. Despite projected demand growth for gasoline having improved, the diesel forecast is now materially lower. With average refinery utilisation rates set to fall in the coming years, the investment slowdown in new refining capacity seems reasonable.

Precisely which refineries will be most impacted remains unclear but high-cost operations in declining demand centres still appear most at risk. Add to this the shifting mix in consumption, as growing naphtha use contrasts with the contraction in gasoline by 2030, and the burden of adjustment looks likely to fall largely on fluid catalytic cracker (FCC) refineries.

Refining profitability – healthy, but challenges ahead

Refining profitability, though weaker than a year ago, appears to have stabilised at above the mid-cycle conditions of the second half of the last decade. Both structural and cyclical factors contribute to this positive margin environment.

The refining industry is and will remain highly competitive. Refineries benefit from significant economies of scale, but generally have access to standardised technologies and processes. Barriers to entry remain high due to heavy capital investment requirements for new refineries and long project lead times. This is further complicated by stringent planning and environmental regulations that stymie additions in many developed economies and reinforce the dominance of established operators. Competitive advantage can be sustained through the development of proprietary technologies, or licensing them from processing technology suppliers (and potentially competitors) for a fee.

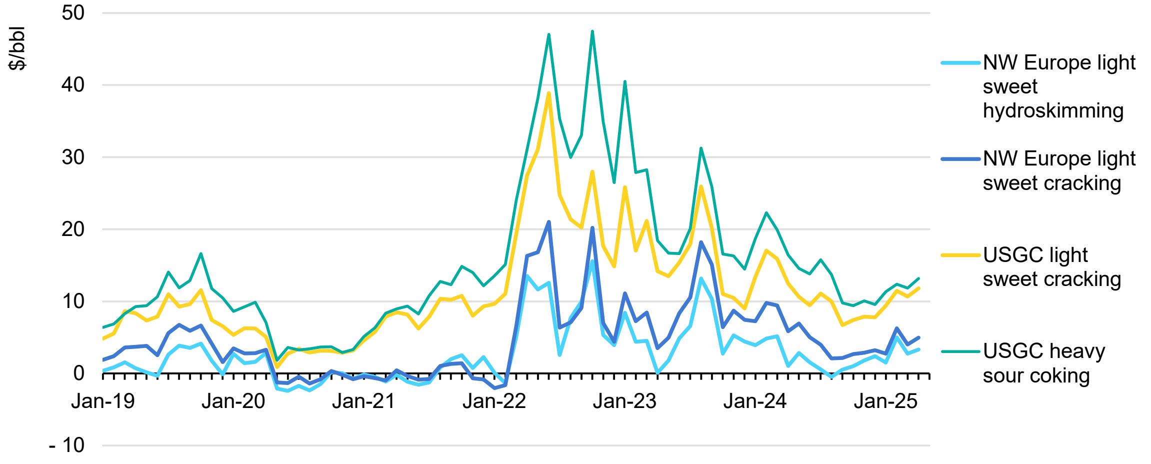
However, refiners often see an incentive to boost runs where additional crude supplies are available. The disparity between the individual incentive to run an additional barrel of discounted crude and the margin implications for the wider market almost always leads to cheap and/or discounted crude supplies undermining industry-wide margins over time.

Historically, more complex refineries have earned higher margins than less sophisticated plants by processing cheaper, heavy/sour crudes or unfinished product feedstocks and converting a greater percentage into premium products such as gasoline, jet fuel and diesel rather than lower value or unfinished grades, including fuel oil. Similarly, refineries in the US Gulf Coast (USGC) or the Middle East with access to cost-advantaged crude, feedstocks or energy have benefited versus higher cost areas such as the North Sea or Asia.

Since the start of the decade, the 22-country OPEC+ group appears to have adopted a production policy aimed at tightening crude markets to support its members’ price and revenue aspirations. One tactic to achieve this has been for

OPEC+ members to pivot supplies to Asia, rather than the Atlantic Basin, with Middle East crude exports to the United States falling to a 40-year low in 2024 at just 530 kb/d. OECD Europe crude imports from the Middle East exhibit a similar trend. This has reduced competition between Canadian heavy sour crude grades such as Western Canada Select (WCS) and Middle Eastern grades and tightened heavy crude supply to the USGC.

US and European refinery margins, 2019-2025



Source: IEA analysis based on prices from *Argus Media Group, All rights reserved.*

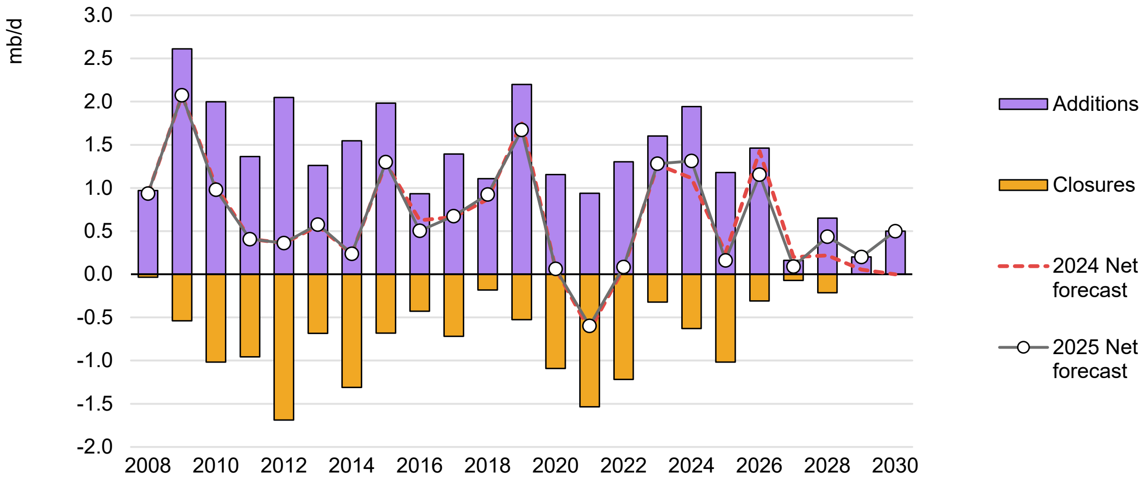
Faced with tight heavy sour crude markets, refineries have had to choose among one of three strategies when optimising processing rates. One option could be to pay up for the spot supplies, thereby sustaining the premium for prompt barrels. Another strategy could be to draw down crude inventories, which from a cash flow perspective might be preferable, but effectively adds to crude market tightness. Lastly, if the margin environment was unfavourable, refineries could cut runs. Viewed through the lens of multi-period game theory, these choices transmit crude market tightness or weakness into the product market.

Hence, crude market backwardation would support product market backwardation where there are limited sources of competing supply. Similarly, widening contango crude market structure would seep into product markets. Consequently, OPEC+ production restraint thus far this decade has been instrumental in supporting the overall level of refinery profits. However, concurrently this restraint has limited the incremental margin available to complex refining versus processing light sweet crude in less sophisticated plants. Moreover, in recent months OPEC+ members have shifted strategy to loosen their production policy and accelerate the reversal of voluntary production cuts. This raises the risk of an oversupplied crude market that could translate into weaker margins if refiners cannot resist the temptation to boost runs with cheaper oil.

Refinery capacity rationalisation needed, but who moves first?

Limited global demand growth for refined fuels and a continued increase in refining capacity worldwide begs the question of where further closures will come from. Closing capacity in recent years, while the industry earned record profits, was hard to justify. However, if margins deteriorate from current levels, industry participants may yet see the incentive to trim capacity. This *Report*'s assessments include only announced closures and thus understate the level of rationalisation needed before 2030.

Annual change in global crude distillation capacity, 2008-2030

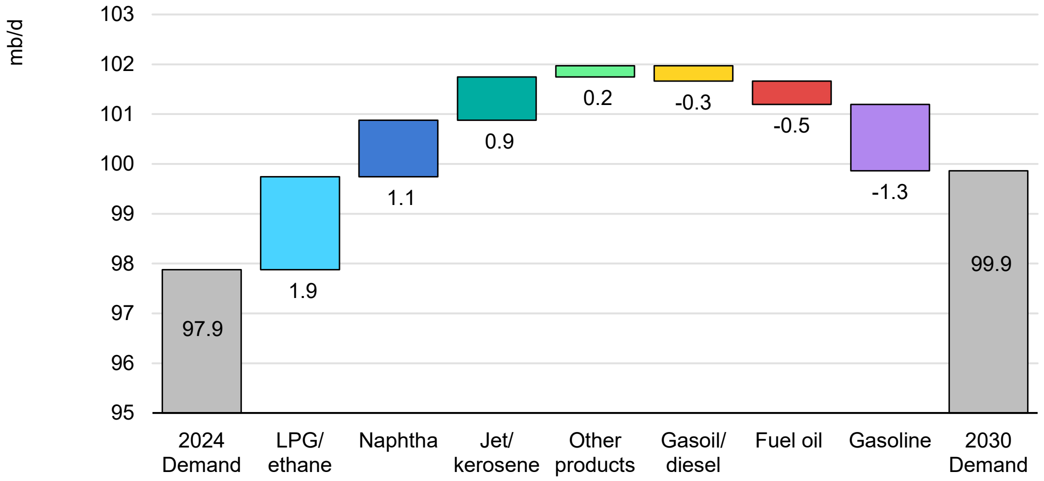


Planned maintenance shutdowns are expensive and if the margin environment is unattractive, or declining regional demand boosts export requirements, operators could consider selling or closing an asset. Moreover, if turnarounds entail additional capital expenditures to meet tighter emissions limits, energy efficiency improvements or low carbon fuels processing requirements that individually or collectively generate a negative net present value for such expenditure, then refiners may opt to defer the work, sell the asset or cease operations. While selling refineries that are operating remains a preferred option for many owners, finding prospective buyers is becoming more of a challenge. Excluding the strategic acquisitions of minority stakes by Middle Eastern national oil companies (NOCs) in several Asian world-scale refineries – often tied to long-term crude supply arrangements – foreign NOCs have become increasingly reticent to commit. With the independent refining sector also in an asset-harvesting mode in developed economies, commodities trading houses have become the most obvious candidates. Furthermore, legislation that keeps previous and existing owners liable for future site remediation costs, for example, in California, could also sway the decision.

Adapting to shifting demand trends: The rise of petrochemical value chains

The toughest challenge facing the refining industry is how to adjust to the shifting demand dynamics and continued robust NGLs production growth. Refineries have honed their output yields over time to match regional demand patterns as dictated by price signals. However, the trends detailed in this *Report* will force many refiners to reassess their current configuration and operations. Arguably, refiners will require price signals to provide incentives to adjust.

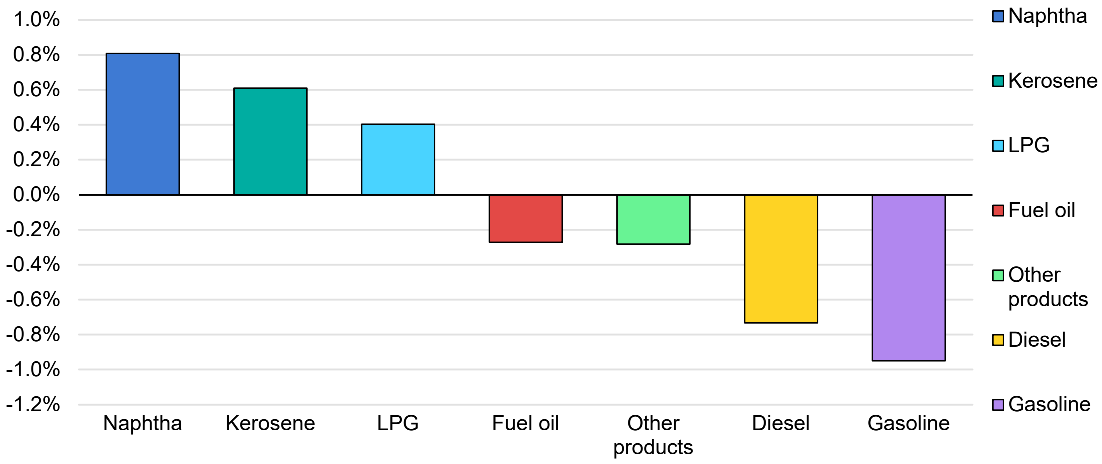
Oil product demand by major product category, 2024-2030



Notes: Demand is net of CTL/GTL volumes and biofuels supply. Demand includes volumes met by NGLs supply. Other products demand excludes crude oil used in power generation.

Market pricing incentivises the maximisation of high value, or relatively scarce products such as gasoline or jet fuel, while penalising lower grade products, or those in surplus, including naphtha and fuel oil. These price differentials drive investment in upgrading capacity. Hence, the prospect of a decline in demand for high value products like gasoline and rising requirements for lower value products presents a seemingly intractable problem for the industry. Refiners also face shifting demand trends in the middle distillate market through to 2030, with falling diesel use, accentuated by a 300 kb/d rise in renewable and bio diesel supplies. This is in sharp contrast to continued jet fuel growth. In theory, refineries can adjust crude distillation cut points to shift output between products. However, such changes may only be possible during planned major maintenance shutdowns that occur every four to six years.

Projected global refinery yield percentage point changes, 2024-2030

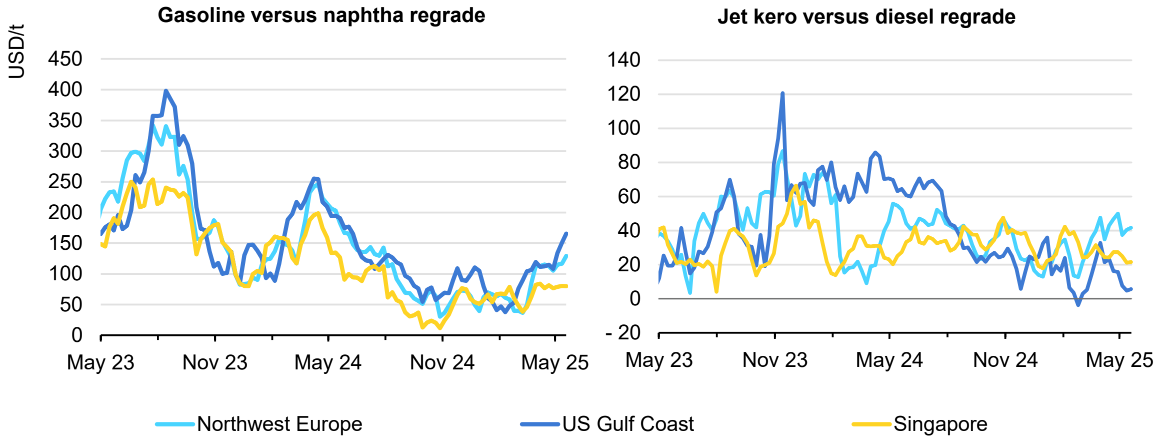


Furthermore, raising jet fuel output may require additional hydrotreating capacity, necessitating further capital expenditure. Similarly, boosting kerosene yields from hydrocracking upgrading units may be possible, subject to similar constraints. Lastly, stringent jet fuel quality specifications may limit the volume available. The price incentive to upgrade diesel to jet fuel varies by region, with European refineries currently seeing the greatest benefit.

The challenge facing refiners in the light distillate market is more complex. The dilemma is how will market participants price the increasing demand for lower-value naphtha and contracting demand for a higher-value gasoline. Moreover, given rising supplies of NGLs-sourced naphtha, refineries do not necessarily set the price of this product. Furthermore, gasoline and naphtha are partially fungible, given that gasoline production typically relies on blending at least six components (including naphtha) to arrive at a finished blend or blend stock. Lastly, not all naphtha is suitable for petrochemical feedstock use. Lighter, paraffinic naphtha is typically used as a feedstock for manufacturing olefins, such as ethylene. However, it can also be processed in isomerisation units to produce a gasoline blending component. Conversely, heavy aromatic naphtha can be reformed to produce high octane gasoline blending component, albeit this contains aromatic chemicals. Incentivising refineries to lower gasoline yields and raise naphtha yields requires a substantial adjustment to current price signals. Effectively, product prices need to dissuade refiners from upgrading low value naphtha into higher value gasoline; something that currently is not happening.

Investment in existing FCC refineries in Europe and the United States to boost output of inherently lower value petrochemical feedstocks appears unlikely. Nor does the prospect of shuttering FCC or hydrocracking units seem feasible, given the poor profitability of hydroskimming refineries.

Regional product price developments, May 2023-May 2025



Source: IEA analysis based on prices from *Argus Media Group, All rights reserved.*

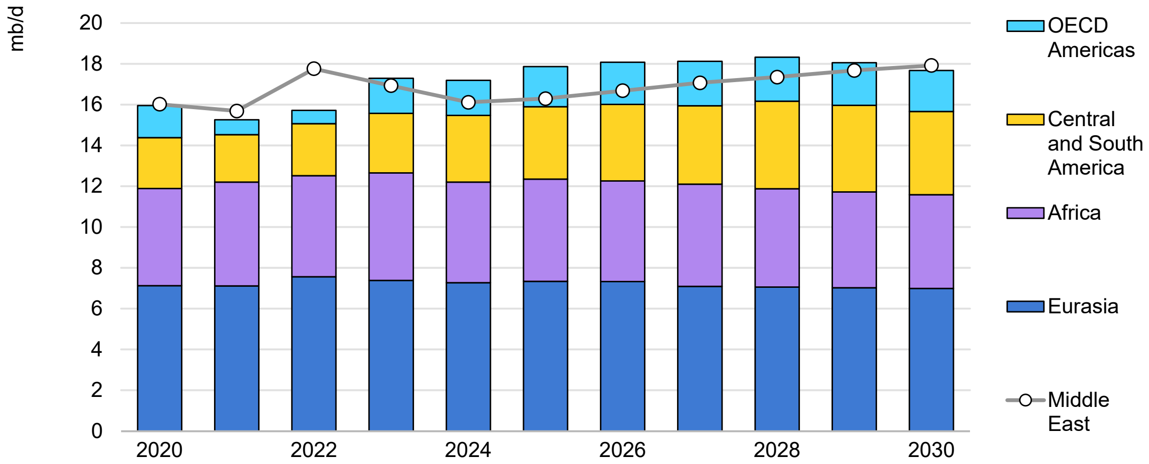
However, new refining projects in China, India and the Middle East are focused on elevating the output of petrochemical feedstocks at the expense of transport fuels. In addition, given that relatively high cost smaller European and US refineries may inevitably be forced to close, an increasing share of crude is expected to be processed in refineries that are specifically designed to maximise petrochemical feedstocks yields, commonly referred to as crude-to-chemicals (CTC) integrated refining and petrochemical hubs. While the profitability of the stand-alone CTC refineries will be below a comparable size fuels refinery, the lower margins achieved on the refining operation will, in theory, be more than compensated for by the integration with massive downstream petrochemical units. Several examples of these refineries are planned or under construction in China and we have adjusted our forecast refinery yields accordingly.

Global crude and refined product trade

Global crude trade will continue to be dominated by the Middle East, with exports from the region increasing from 16.1 mb/d in 2024 to 17.9 mb/d by 2030. This is equivalent to the combined exports from the Americas, Africa and Eurasia. Higher Americas crude production will push additional barrels from the Atlantic Basin into markets East of Suez that are short of crude. Brazilian and Guyanese crude exports will increasingly head east, as 800 kb/d of additional supplies boost Central and South America's crude exports to 4 mb/d by 2030. This follows on from the increase in North American exports to Asia in recent years, first of US LTO and more recently of Canadian heavy crudes following the expansion of the

Trans Mountain Expansion (TMX) pipeline. Atlantic Basin import hubs, e.g. Europe and the US Gulf Coast will compete for crude supplies in the short term, before weaker local demand dampens refinery activity.

Regional crude export flows, 2020-2030



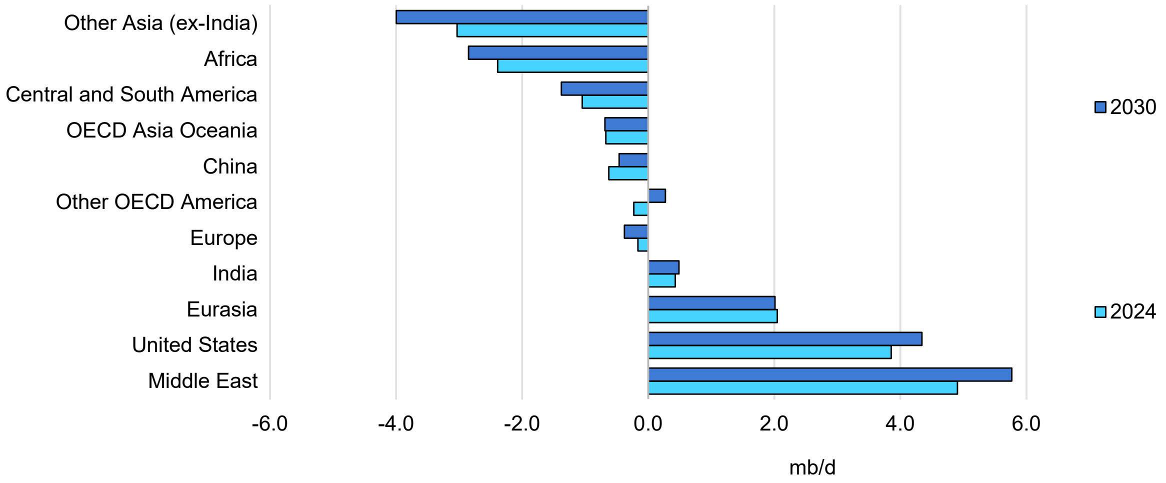
Note: Crude export flows are net of intra-regional flows.

The Middle East is set to lead regional product export gains over the balance of the decade, driven by higher LPG, naphtha and fuel oil volumes. In part, this reflects Qatar's liquified natural gas (LNG) expansions and increased Saudi Arabian non-conventional gas production. Moreover, we expect Middle East refineries to push jet fuel output higher at the expense of diesel, in line with the global trend. Rising fuel oil exports are underpinned by the region's shift towards natural gas in the power sector.

More broadly, several countries that have driven much of the recent rapid expansion in product exports will see only limited progress. In India, rising domestic demand caps export gains, while in the United States falling crude runs reduce surplus product output. Chinese refined product exports are assumed to remain at close to current levels of 40 Mt per annum. However, this could be challenged either by the country's push to cut carbon emissions, or conversely boosted if the government were to yield to pressure from the refining industry to support economic activity.

Jet fuel is set to face the tightest supply conditions over the balance of the decade. Continued jet fuel demand growth will require refiners to boost yields in the face of flat or falling crude runs. Regional export hubs, such as the Middle East, Eurasia and India will see strong demand from regions with continued import needs, such as Europe, Africa and Latin America.

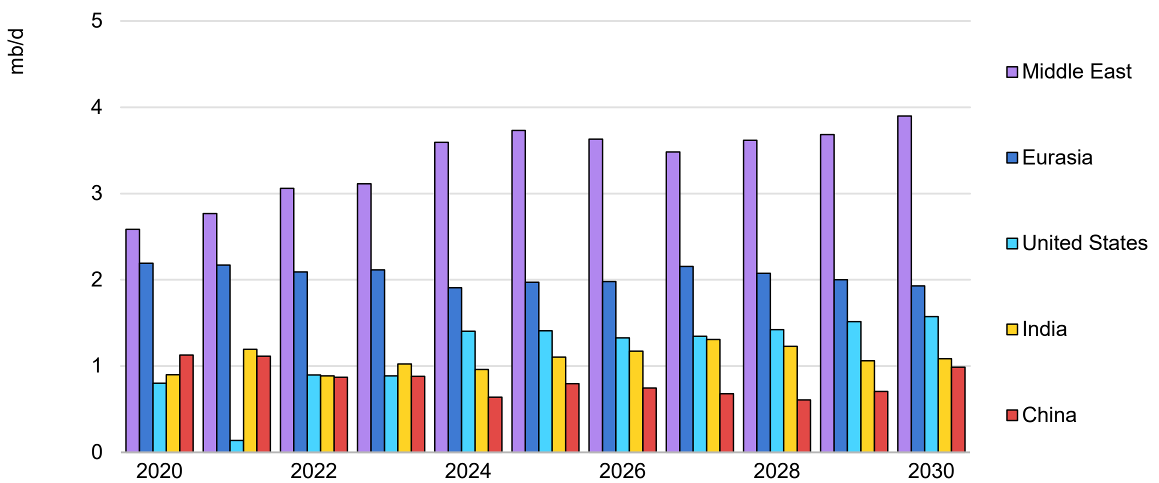
Regional product trade, 2024-2030



Note: Regional product trade includes NGLs.

Additional jet fuel supplies will effectively be drawn from the diesel market, which sees falling demand, even though long-term import dependent regions such as Latin America and Africa will continue to need to attract supplies. Conversely, European diesel imports will decline as diesel demand ebbs and despite lower refinery crude processing. Depending on the speed and scale of the adjustment by European refiners, the region's growing jet fuel import requirements could rival or possibly overtake its diesel import needs by the end of the decade.

Major refined product exporters, 2020-2030



Note: Refined product exports exclude NGLs and biofuels.

Gasoline trade in the Atlantic Basin will see sustained Latin American imports surpassing North American import requirements. European gasoline exports will stabilise in the short term, before pushing higher by the end of the decade as regional demand starts to decline. African gasoline imports should dip as regional crude runs ramp up in the short term, but the continent is expected to see increased product imports from 2026 onwards, as continued strong demand once again outpaces crude processing growth.

How can refiners navigate the challenges ahead?

Global crude distillation unit (CDU) capacity has grown by 13.5 mb/d since 2006, mostly driven by China (+8.4 mb/d), the Middle East (+4.6 mb/d) and India (+2.7 mb/d), while OECD countries decreased by 5.4 mb/d. This regional variation highlights the divide between OECD and non-OECD countries where markets, margins and macroeconomic incentives differ for refiners. Regional disparities are set to continue through 2030 as capacity continues to contract in the OECD (-730 kb/d) but expands by 3.3 mb/d in the rest of the world, led by China (+870 kb/d) and India (+960 kb/d).

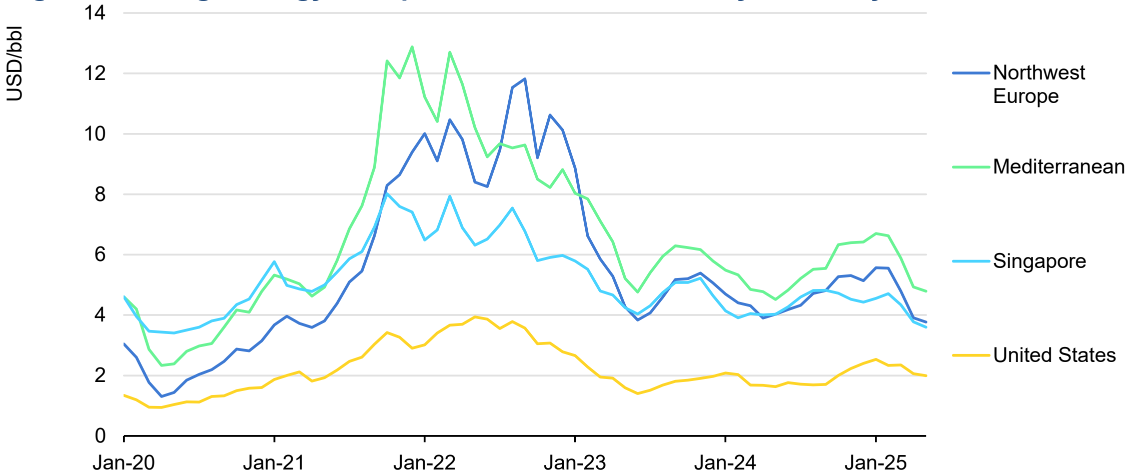
The long-term drivers of growth are shifting. Gasoline demand (net of biofuels) is already close to its global pinnacle this year. OECD demand peaked last decade, pulled lower by OECD Asia Oceania and OECD Americas demand contracting since 2016-17, while OECD Europe is forecast to plateau through 2027 and then decline. Similarly Chinese gasoline demand is now falling from its post-Covid highs. Diesel demand in all three OECD regions and China, which accounts for more than 50% of the global total, is also contracting. Conversely, jet fuel demand will continue to grow through the end of the decade. Against this shifting demand outlook, key variables such as energy cost, feedstock accessibility, tighter product specifications, environmental regulations, alternative mobility solutions, and the energy mix in both transport and power generation will define the future of refineries.

Near term, to survive in a competitive market with surplus capacity, individual refineries and the industry more broadly will have to continuously reassess investment strategies to maintain a healthy margin. A refiner can adapt in the medium term in many ways, but not all are economically viable, depending on the region and market. For example, major maintenance turnarounds (TAR) occur every four to six years and are essential for extending the refinery's operational life. TARs are planned years in advance, and the refinery's management prioritises critical investment areas such as repairs, new product specifications and renewing or upgrading units. To operate, a refiner needs the approval of the government. Consequently, a portion of the investment usually targets improving environmental safety and reducing emissions. In the European Union refiners need to ensure that safety standards meet the Seveso 3 Directive (high risk industries safety obligations) and environmental legislation. A TAR costs a minimum of USD 50 million and frequently several hundred million dollars. Whether refiners will recoup a return on this investment before the next TAR is a major budgeting challenge.

Focus on efficiency, efficiency and efficiency

Energy efficiency improvements remain a key source of optimisation gains. Energy costs represent about 30-50% of the total operational expenditures. Disparities in energy costs and accessibility impact refinery configurations in each region. The 2022 European natural gas price spike following Russia's invasion of Ukraine boosted the average energy cost to an average of USD 9.90/bbl in Northwest Europe (NWE) as compared to USD 3.50/bbl in the United States. Consequently, EU and OECD Asia refiners have invested in energy efficiency and consolidated their existing assets, switching from fuel oil to natural gas boilers and worked to cut energy intensity at the unit level. For the last two decades, benchmarking has been an essential exercise to improve process efficiency.

Regional average energy cost per barrel of feed, January 2020-May 2025



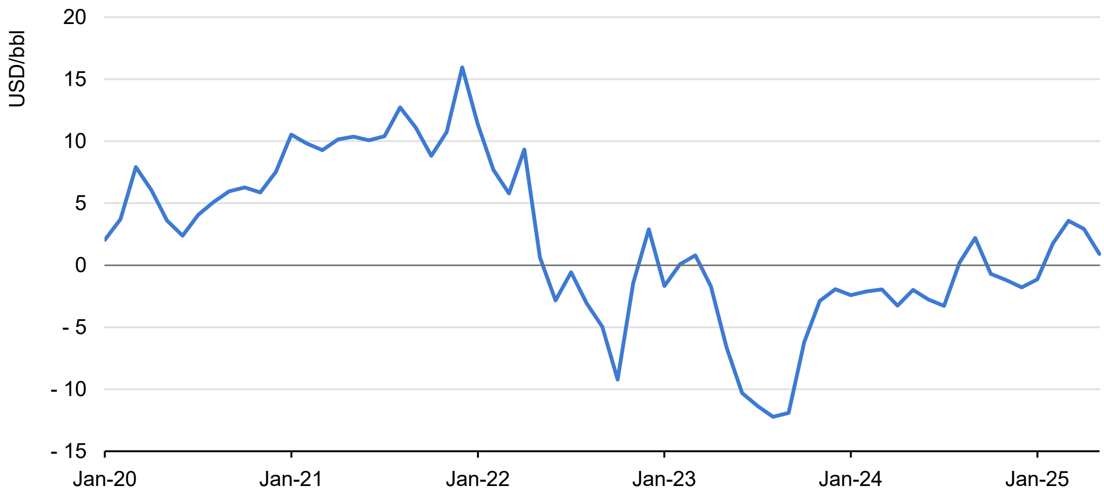
Note: The calculations consider natural gas, LPGs, ethane, fuel oil, electricity, imported heat, petroleum coke consumption and CO_2 credits as specified in the IEA's refining margins methodology.

How European refiners can boost petrochemical yields

Adapting to the shift in global demand trends will require refiners to rapidly change output yields that have been largely enshrined for decades. One strategy adopted by refiners involves modifying the FCC operations and output. The FCC is used to convert heavy distillation cuts – typically vacuum gasoil, but also atmospheric residue – into lighter and higher value gasoline, gasoil, gases and propylene. The unit is key to boosting a refinery's overall margin and is central to the internal flows in the plant. An FCC can be switched from its "conventional" configuration that maximises gasoline output (or gasoil in the case of European markets) to a high severity set-up that raises production of petrochemical feedstocks. This mode of operation requires increased temperatures and different catalysts to treble the output of propylene. However, this operational switch increases energy costs and generates more coke on the catalyst and therefore more CO_2 emissions.

If Northwest European refiners were facing a situation like China's – namely higher demand for petrochemical feedstocks, lower gasoline consumption and the consideration of carbon credits – would it be more advantageous today to increase propylene production at the expense of gasoline? Over the past five years, the shift to a propylene-max mode of operation would have typically made an average of USD 2/bbl of feedstock but at times during that period – notably post the Russian invasion of Ukraine – it would have cost a refinery as much as USD 12/bbl of feedstock. It is also a question of scale. On average, European refineries have FCC capacity equal to 20% of installed distillation capacity. Consequently, the 10% yield shift in FCC output to propylene would only equate to a 2% change in overall yields.

Northwest Europe high severity FCC margin uplift, January 2020-May 2025



Note: Margin uplift to high severity configuration compared to conventional configuration for NWE FCCs in USD/bbl of feed processed.
Source: IEA analysis based on prices from *Argus Media Group, All rights reserved.*

Nevertheless, such optimisation may offer short-term relief to refiners if demand for refinery grade propylene is sufficient to absorb additional output. Longer term, as European gasoline demand begins to fall and considering that the current EU propylene market is already long, the future of FCCs in Europe may be in danger, with further closures likely.

Adapting to declining regional demand

Alternatively, the same feedstocks that feed FCCs can be used in a hydrocracking unit (HCK) to produce much higher yields of middle distillates, such as diesel and kerosene. Compared to FCC units, which upgrade through a process of carbon rejection, HCK units hydrogenate and crack feedstock to produce a greater share of, and better quality, middle distillates than FCCs. However, diesel demand in OECD Europe and the United States will decrease by 560 kb/d and 180 kb/d, respectively by 2030, underscoring the need for refiners to adapt their HCK units.

Changing the catalyst and severity of operation and hydrogenation to boost kerosene output remains an option, subject to meeting jet fuel's tight quality specifications. However, even though we anticipate Europe will remain a net importer of diesel, these solutions will fail to match the rapid demand contraction expected by the end of the decade. Consequently, not all European refineries will necessarily be able to operate their hydrocracking units profitability.

Given that a refinery is a heavily interconnected chain of processing units, any change to a unit inevitably affects the overall output. For example, both HCKs and FCCs produce iso-butane and butylene, which serve as feedstocks for the alkylation unit that produces a gasoline blending component (alkylate) that is low aromatic, low volatility and high-octane. This high quality component is crucial to meet current tight quality specifications. Therefore, any reduction in capacity or performance can limit feedstock availability to the alkylation unit, potentially complicating gasoline blending.

Despite the efforts of refiners to remain competitive and viable, pressure is mounting on operations in Europe, OECD Asia Oceania, and more recently the United States. In the 2024-26 period, cumulative refinery closures for these regions total 1.3 mb/d. We only include announced closures in our forecasts, but lower regional processing rates in this *Report* reflect the risk that further closures are likely. The European Fuel Manufacturers Association's (CONCAWE) recent study on "The potential evolution of Refining and Liquid Fuels production in Europe" suggests a reduction of 2.1 mb/d of CDU capacity in Europe by 2030 is possible.

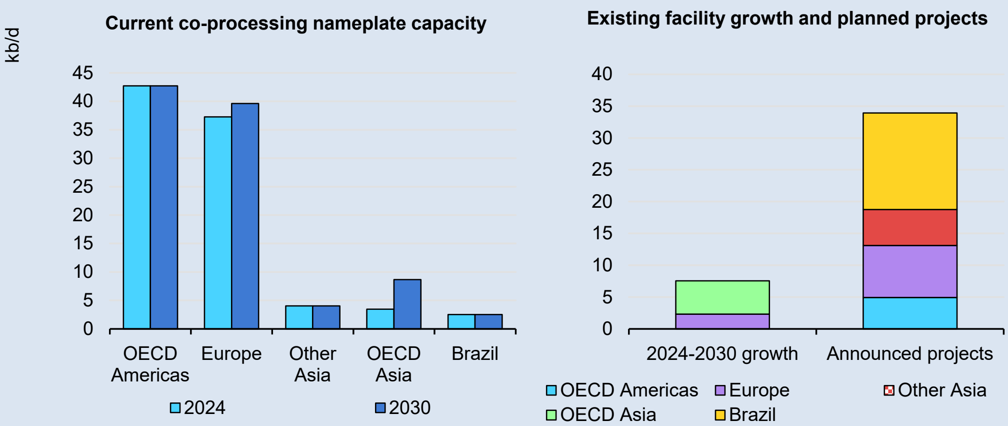
Biofuels co-processing expanding

During the last decade, stronger legislation on biofuel blending limits and better economic incentives supported by higher subsidies and prices have pushed refiners to process vegetable oils, waste oils and fats in hydrotreating units (HDT) to produce hydrotreated vegetable oils (HVO) and, more recently, sustainable aviation fuel (SAF).

Processing biogenic feedstocks to make HVO has the advantage of producing a fuel with similar properties to diesel. HVO, which can be blended up to 100%, is a good alternative to biodiesel (fatty acid methyl ester or FAME) that has lower blending limits. A recent trend in the refining landscape is the co-processing of renewable feedstocks with conventional crude and feedstocks. Incorporating a 10-20% vegetable oil feedstock to existing hydrotreating units (HDTs), and to a lesser extent to hydrocrackers (HCKs), can scale-up HVO/SAF production while saving capex compared to building new stand-alone plants. In the case of a unit at 100% utilisation rate, the refiner must reduce the intake of feedstocks derived from crude oil to allow for the addition of vegetable oil to the HDT or HCK. One of the main constraints to produce HVO/SAF is the higher hydrogen consumption from renewable feedstock, due to its oxygen content that is removed via hydrogenation. Other co-processing pathways are under development, for example the use of FCCs that do not consume hydrogen, to treat biomass-derived feedstocks such as pyrolysis oil or Fischer-Tropsch waxes

By 2030, expansions at existing sites could increase global co-processing capacity by 7 kb/d from the 2024 baseline of 90 kb/d. A further 34 kb/d of proposed projects – if realised – could lift capacity to 130 kb/d. Currently SAF and HVO remain the most economically interesting biofuels to produce. In 2024, co-processing 10% of used cooking oil (UCO) with 90% vacuum gasoil (VGO) was profitable for NWE hydrocrackers. This presents a good opportunity for European refiners, even as diesel demand is declining, with hydrocrackers having the capability to maximise kerosene production over diesel.

Refinery co-processing capacity and additions, 2024-2030



Source: IEA analysis based on data from *Argus Media Group, All rights reserved.*

However, in both cases vegetable oils need an extra pre-processing treatment to remove impurities that can affect the reliability of the upgrading unit, and to prevent catalyst deactivation and pipe corrosion. A hydrogen-long refinery will prefer hydrotreating units to maximise HVOs or SAF production over FCC and HCK co-processing where biogenic feedstocks are limited by availability or technological bottlenecks.

There is a clear trend to maximise the use of residue and waste oils because they have low emission intensity and meet feedstock requirements in the European Union. The high demand for these feedstocks resulted in a surge of UCO costs in 2025, pushing processing margins negative in the United States in April 2025. Further legislation to increase the ratio of biofuel products to finished products is planned in the coming years. For example, the European Union has set a mandate for 6% SAF blending by 2030.

Refining capacity

Global refining distillation capacity (including both crude distillation units and condensate splitters) is on track for a net expansion of 2.5 mb/d between 2024 and 2030. Approximately 4.2 mb/d of new and expanded capacity is scheduled to come online, offset by around 1.6 mb/d of announced closures. Consequently, refining capacity is forecast to reach 108.3 mb/d by 2030. However, the pace of growth is significantly slower than the historical trend, with the five-year average annual net additions at just over 400 kb/d. This represents half of the average for the post-GFC decade of nearly 800 kb/d. The striking slowdown in demand growth for refined products weighs heavily on investments in refining capacity.

Regional refinery capacity and utilisation, 2024-2030

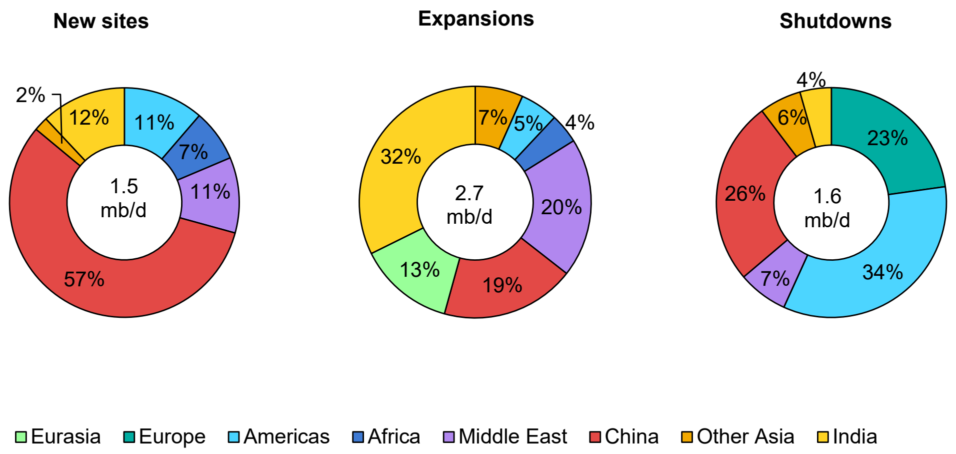
	2024	2030	Change	2024	2030	Change	2024	2030
	Total capacity (mb/d)			Refinery throughput (mb/d)			Utilisation rates	
OECD Americas	22.2	21.8	-0.4	19.1	18.6	-0.5	86%	85%
United States	18.3	17.7	-0.5	16.1	15.5	-0.6	88%	87%
C and S America	5.7	5.9	0.1	3.7	3.8	0.0	64%	64%
OECD Europe	13.7	13.3	-0.4	11.2	10.3	-0.8	82%	78%
Other Europe	0.8	0.8	0.0	0.5	0.4	0.0	57%	53%
Africa	3.7	4.0	0.2	1.8	2.2	0.4	47%	55%
Eurasia	9.2	9.3	0.2	5.7	6.0	0.3	62%	64%
Middle East	11.6	12.2	0.6	9.8	10.0	0.3	84%	82%
OECD Asia	7.2	7.2	0.0	5.6	5.3	-0.3	78%	74%
China	18.5	19.5	0.9	14.6	14.9	0.2	79%	76%
Other Asia	13.1	14.3	1.3	10.8	11.8	1.0	82%	82%
India	5.8	6.8	1.0	5.4	6.3	0.9	92%	92%
World	**105.7**	**108.3**	**2.5**	**82.6**	**83.3**	**0.6**	**78%**	**77%**
Atlantic Basin	53.8	53.6	-0.2	41.1	40.5	-0.7	76%	76%
East of Suez	51.9	54.7	2.7	41.5	42.8	1.3	80%	78%

Investments continue to diverge regionally through the end of the decade. Atlantic Basin refining capacity will remain in structural decline, driven by transportation decarbonisation policies and mounting cost pressures. Conversely, countries East of Suez continue to invest in both world-scale petrochemical-oriented refineries and smaller domestic-focused plants. Consequently, the refining system is entering a new phase – defined not only by expansion, but by adaptation. By 2026 East of Suez refining capacity will exceed the Atlantic Basin for the first time.

Announced shutdowns total 1.6 mb/d for 2025-30, equivalent to an annual decline of around 250 kb/d. Although slower than the average of 800 kb/d over the past decade, we only include announced shutdowns in the forecast, as refiners typically confirm closure plans 12 to 18 months in advance. As such, there is potential for substantial additional closures in Europe, North America and China and we have adjusted utilisation rates lower for heavily exposed regions in anticipation of further capacity rationalisation. In 2025, over 1 mb/d of capacity will be closed – making it the largest single year of rationalisation since 2022. Most of this is concentrated in OECD markets. The United States accounts for over 400 kb/d of closures, followed by Europe with 370 kb/d.

Conversely, 2026 will see nearly 1.5 mb/d of gross capacity additions, driven overwhelmingly by India, China and the Middle East, with announced closures totalling only 300 kb/d. Greenfield investments have all but stalled, with expansions, upgrades and petrochemical integration dominating planned projects – reflecting a shift towards strategies that enhance margins without adding substantial new crude intake. This signals a structural transition in refining – from volumetric growth to value, improved flexibility, emissions mitigation and optimising product yield.

Capacity additions and closures breakdown by region, 2024-2030



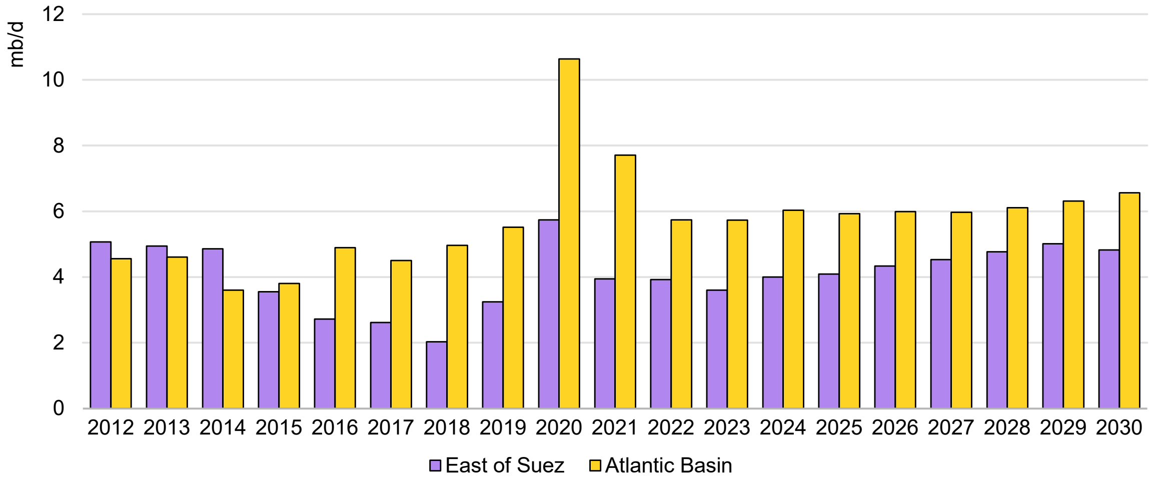
Regions East of Suez remain the anchor of future growth. By 2030, China will retain its status as the world's largest refiner, with capacity rising to 19.5 mb/d, even though excess capacity will remain at nearly 2.2 mb/d. The United States follows at 17.7 mb/d, with India at 6.8 mb/d, just behind Russia with 7.1 mb/d.

Excess refinery capacity – a catalyst for change

Excess capacity has been a long-term feature of the refining industry and looks set to increase by 1.8 mb/d through the forecast period, to 11.4 mb/d by 2030. It is determined by the surplus of installed CDU and condensate capacity, adjusted for average maintenance (which we assume is 14%) above projected refinery runs. Unlike the upstream component of oil markets, neither countries nor companies hold a strategic buffer of refining capacity to stabilise product cracks, preferring to allow international trade to meet local product imbalances.

Conversely, cyclical over-investment – initially in OECD countries and, more recently, in markets such as China – have resulted in a structural surplus. Shifting trends in product demand have exacerbated this build-up of excess capacity, with the highly competitive product markets exposing capacity that is poorly configured to product market needs. Arguably, operational reliability issues, particularly when regional refining systems are running at high levels of utilisation, make the case for an additional 6-8% of marginal capacity that can be brought into service. Nevertheless, growth through 2030 in Asia, the Middle East, and Africa – serving both domestic demand and export markets – will continue to reshape the global downstream map.

Refining industry excess capacity, 2012-2030



Note: Assumes 14% downtime for maintenance is required.

East of Suez, excess capacity reaches nearly 4.9 mb/d by 2030, 820 kb/d higher than in 2024, with China and Other Asia contributing to most of the rise. In OECD Asia Oceania, excess capacity in both Japan and Korea will increase by 100 kb/d and 180 kb/d respectively to 500 kb/d due to declining demand. Singapore's excess capacity will reach 220 kb/d, with its long-term viability continuing to depend on export margins.

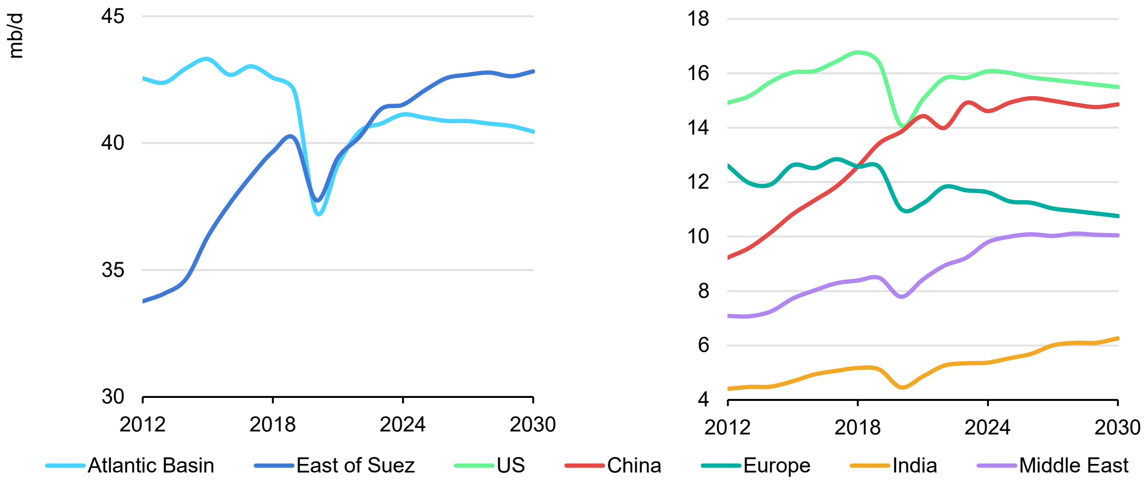
In the Atlantic Basin, excess capacity will grow marginally to 6.5 mb/d by 2030. The Americas will hold steady at 1.7 mb/d while Africa's excess capacity will total 1.4 mb/d, with much of it concentrated in underinvested plants with low-utilisation rates. In OECD Europe, excess capacity will swell by 650 kb/d to 1.6 mb/d, making it one of the most vulnerable regions for capacity rationalisation. In Eurasia, modernisation and a gradual recovery from conflict-related damage keeps excess capacity steady at 400 kb/d, but the region currently still holds a surplus of 2.4 mb/d, with utilisation expected to improve only modestly.

Regional developments

Atlantic Basin

Crude throughput in the Atlantic Basin is expected to fall by 670 kb/d to 40.5 mb/d by 2030, largely on weaker European and US runs. This compares with a modest 210 kb/d decline in capacity, as growth in Africa and Eurasia partially offsets closures in Europe and the United States. Excess capacity remains high, at around 6.5 mb/d, with average utilisation dipping slightly to 76%. Contracting demand in OECD markets like North America and Europe puts older, less efficient assets at risk.

Atlantic Basin versus East of Suez refinery throughputs, 2012-2030



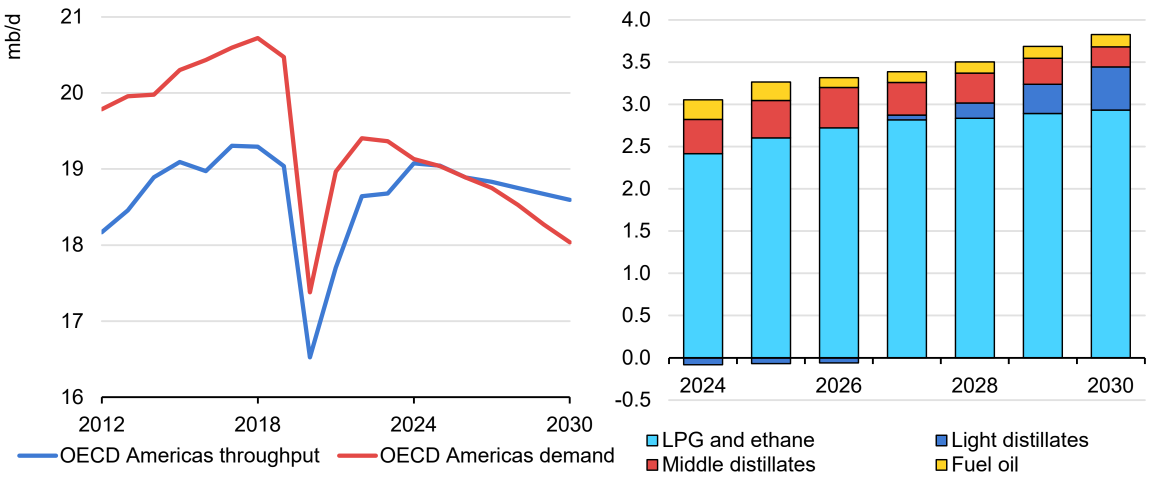
Product exports rise by 320 kb/d to 3.5 mb/d, as regional demand for refined products contracts. Import requirements for transport fuels, including gasoline and diesel, will decrease by 390 kb/d, as demand drops by 1.5 mb/d due to the expanding EV fleet and increasing vehicle efficiencies. Conversely, ethane and LPG demand grows by 700 kb/d to 8.1 mb/d, however NGLs supply increases faster, resulting in a net 110 kb/d increase in exports to 1.7 mb/d. These volumes will increasingly seek outlets in emerging market petrochemical hubs in Asia and growing LPG demand centres – particularly in Africa – where clean cooking initiatives are accelerating.

Our upstream assessment for the Atlantic Basin sees crude production increasing by 1.1 mb/d to 48.6 mb/d in 2028, before slipping back to 47.7 mb/d by 2030. Consequently, we expect the Atlantic Basin's crude surplus to widen by approximately 870 kb/d to 7.1 mb/d by 2030. Similarly, NGLs supply increases by 860 kb/d to 9.2 mb/d by 2030.

OECD Americas

The OECD Americas faces the challenge of declining regional refined products demand over the outlook period. Consequently, refining throughputs, capacity and utilisation are all forecast to contract by 2030. Average regional capacity utilisation, currently at 86%, dips to 85.2% by 2030, with slightly lower US rates offset by improved Mexican utilisation. As oil consumption growth falters, demand for refined product falls by close to 1.1 mb/d by 2030, significantly outpacing the region's 370 kb/d decline in capacity.

OECD Americas refinery runs, demand and net product balances, 2012-2030



IEA. CC BY 4.0.

The **United States** continues to dominate regional crude processing capacity, but the sector has entered a phase of structural contraction. Despite recent expansions (most notably ExxonMobil's 250 kb/d CDU at Beaumont, Texas, commissioned in early 2023), gains are being overshadowed by a string of closures. In 2025 alone, the United States is set to close over 400 kb/d of capacity. On the Gulf Coast, LyondellBasell's 265 kb/d Houston refinery permanently shut in Q1 2025 after efforts to find a buyer proved unsuccessful.

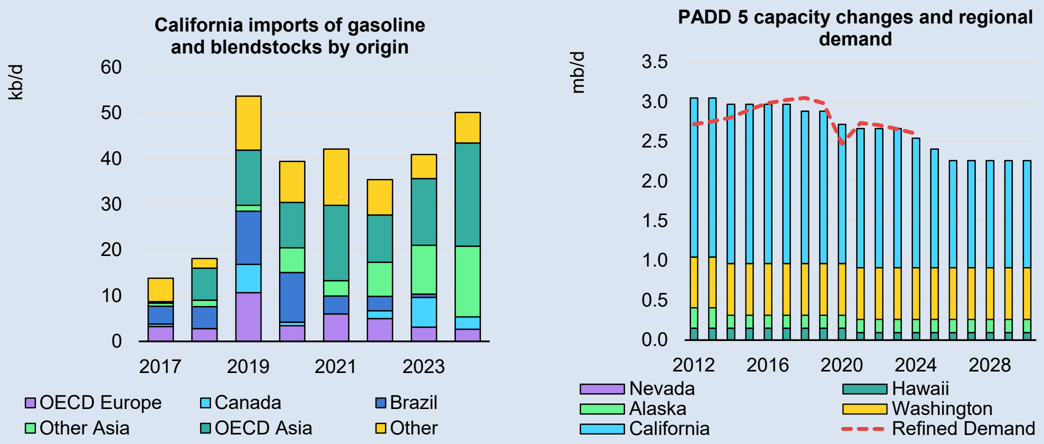
California is undergoing a particularly sharp rationalisation (see *All eyes on West Coast refineries*). Phillips 66 shuttered its 120 kb/d Rodeo refinery in early 2024 and will close its 140 kb/d Wilmington facility in Q4 2025 as part of a broader portfolio optimisation strategy. Further losses are expected next year, with Valero's 145 kb/d Benicia refinery slated for shutdown and repurposing in H1 2026 amid intensifying environmental compliance costs and regulatory pressure. These developments exemplify a broader national trend of refinery attrition that has closed 2.6 mb/d of capacity since 2010. Factors contributing to the decline include ageing infrastructure, higher costs from environmental regulations in many states and rising investment requirements to maintain competitiveness and meet nationally mandated emissions reduction targets.

All eyes on West Coast refineries

Refining capacity on the US West Coast (PADD 5) is undergoing a sustained and significant contraction. Between 2018 and 2026, over 700 kb/d of crude distillation capacity has or will be closed. This represents nearly one-quarter of the region's operational baseline. The wave of PADD 5 closures began with Paramount Petroleum's 85 kb/d refinery and Island Energy's 55 kb/d Honolulu plant in late 2018, and Marathon's 170 kb/d Martinez refinery in 2020. In 2024 Phillips 66's repurposed 120 kb/d Rodeo facility for renewable fuel production. By the end of 2024, cumulative crude processing capacity losses had reached 420 kb/d – more than triple the 130 kb/d decline in regional transport fuel demand over the same period. The 2025 slated closure of Phillips 66's 140 kb/d Wilmington refinery will lift total shutdowns to 560 kb/d. The latest announcement for the 2026 closure of Valero's 145 kb/d Benicia refinery will leave only 12 crude oil refineries in California, with a total capacity of 1.3 mb/d.

These shutdowns are not being driven by poor refining margins – which remain relatively healthy – but by financial and policy challenges, including a cleaner energy landscape that increasingly favours renewable fuels and vehicle electrification. These include stringent environmental compliance costs, extensive permitting hurdles, and unique fuel specifications such as the California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) for gasoline, alongside a progressively restrictive policy framework shaped by the Cap-and-Trade system that limits GHG emissions and the Low Carbon Fuel Standard (LCFS).

US West Coast refined product trade and capacity



Sources: IEA analysis based on trade data from *Kpler*. PADD 5 West Coast demand data is from the US EIA.

While the long-term shift toward EVs and more efficient internal combustion engine (ICE) powertrains is expected to gradually lower gasoline demand, the current rate of refinery closures is outpacing this transition. The pace of capacity rationalisation keeps the region net short products and requires continued imports, particularly for gasoline. In 2024, California imported nearly 50 kb/d of gasoline and blending components, largely from Asia. However, few refineries globally are configured to easily meet California's strict fuel standards, limiting alternative supply sources. The US Gulf Coast serves as a source of replacement barrels, though high shipping costs associated with the compliance of the Jones Act – which mandates cargo transported by water between US ports must be carried on US flagged, built and owned vessels – may limit arbitrage opportunities unless price differentials widen.

The tightening product balance in California is also expected to ripple into adjacent markets – including Arizona, Nevada and the Pacific Northwest – which rely on inter-regional marine and pipeline flows from the state. This structural rationalisation is likely to increase price volatility and import dependency over the medium term.

Mexico's state-owned company Pemex continues to face difficulties boosting downstream output as it seeks to substitute imports with domestic production of products. The much-delayed 340 kb/d Olmeca refinery in Dos Bocas on the Gulf of Mexico is currently ramping up, and expected to reach full operations in 2026. The first 170 kb/d phase started in late 2024, with the second tranche expected to be running later this year. This will be a major milestone in addition to Pemex's overhaul programme for six refineries, which includes upgrading units at Tula, Salina Cruz, and Salamanca. Supported by close to USD 8 billion in planned investments, Mexico aims to secure self-sufficiency and retail price stability via increased production of gasoline, diesel and jet fuel. However, if successful by the end of the decade, the expected decline in Mexican crude production will push the country closer to becoming a net crude importer and tighten supplies of heavy sour crude for US Gulf Coast refineries.

Crude and product balances

The net crude export position of OECD Americas is expected to gain 290 kb/d through 2030, to around 2 mb/d. This stability masks underlying structural shifts within the region's supply profile. Canadian heavy crude and diluted bitumen (dilbit) production is set to rise significantly (+470 kb/d), boosted by upstream expansions and improved takeaway capacity, which directs as much as 600 kb/d into Asian markets. However, this gain is more than offset by a 660 kb/d decline in conventional crude and LTO production, driven primarily by declines in Mexico and slowing output growth in the United States.

Net product exports will rise by a significant 990 kb/d to 4.6 mb/d by 2030. More than half of the increase is in LPG and ethane, which combined will reach 2.9 mb/d by the end of the decade, reinforcing the region's role as a key supplier of petrochemical feedstocks. The gasoline/naphtha balance shifts towards being net long by 2030, driven by rising pentane plus/naphtha supply from NGLs. Gasoline net imports shrink by 550 kb/d to just 160 kb/d as domestic demand shifts into structural decline and regional supplies rise. Notably, the launch of Mexico's Dos Bocas refinery will play a critical role in enabling the region to shift to a net exporter position in light ends by 2030. By contrast, middle distillate balances tighten modestly, as available export volumes decline amid refinery closures and continued jet fuel demand growth.

Challenges

The OECD Americas refining sector is navigating a complex and often contradictory landscape. Despite healthy post-pandemic refining margins (averaging 20% above 10-year norms), closures continue as costs of regulation and modernisation outweigh future cashflows. This paradox reflects a shift from current cash-flow-based measures of viability to include future capital investment requirements. Hence, refineries are shutting not on the basis of current profits, but due to the prohibitive cost of modernisation. With US demand for refined gasoline having peaked late last decade, many operators are foregoing major upgrades. This trend favours larger, integrated plants capable of processing a wider crude slate and accessing export markets. By contrast, older, smaller sites – particularly those isolated from logistic hubs or with limited product flexibility – are increasingly vulnerable.

Central and South America

Refining capacity in Central and South America sees minimal change through 2030, rising by just 130 kb/d to 5.9 mb/d. The increase is driven solely by Brazil's phased expansion of its RNEST refinery in Abreu e Lima. A 15 kb/d expansion was completed in Q1 2025, completing the Train 1 modernisation and emissions retrofitting. A more substantial addition of 115 kb/d from Train 2 is scheduled for Q2 2029, which will bring RNEST's total capacity to 245 kb/d. This project, stalled since 2015, has been revived under Petrobras' new downstream strategy that will see domestic crude runs effectively meet product demand.

Refinery throughput in Central and South America increases by 50 kb/d over the forecast, yet at 3.8 mb/d remains well below nameplate capacity, reflecting structural underutilisation. Venezuela accounts for the majority of this surplus, with 1.3 mb/d of installed capacity continuing to operate at less than 25% utilisation due to years of underinvestment, poor maintenance and ongoing sanctions. Similarly, PDVSA's 320 kb/d Isla refinery in Curaçao continues to sit idle. Once considered a key regional supplier, the facility has yet to secure a viable operator since PDVSA ceased operations in 2019. With refined product demand rising by 350 kb/d to 5.2 mb/d by 2030, the lack of regional refining activity reinforces import dependence for product supply.

Crude and product balances

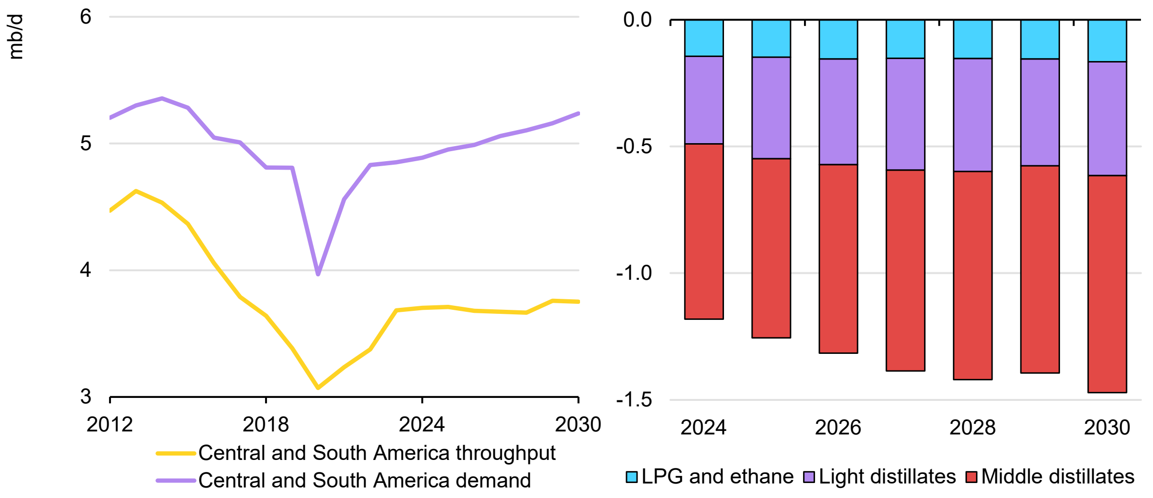
Central and South America's net crude exports growth of nearly 800 kb/d over the forecast period, to 4 mb/d by 2030, is particularly striking. This is the second-largest regional increase globally, after the Middle East. The surge reflects a widening disconnect between upstream supply and refining capacity, with limited investment in domestic refining infrastructure leaving much of the region's output – particularly medium and heavy sweet crudes – destined for export. While the United States continues to absorb a portion of these volumes, the distillate-rich crudes are of particular interest to refineries in China, India and Europe.

Conversely, product import reliance in Central and South America is set to widen by nearly 330 kb/d to 1.4 mb/d – broadly in line with a 350 kb/d increase in refined product demand. Diesel leads the growth, adding 140 kb/d to import requirements, while gasoline and naphtha together contribute a further 100 kb/d. However, when Mexico's Dos Bocas refinery ramps up, this will boost North American gasoline and diesel exports, freeing up volumes, particularly from the US Gulf Coast to meet the growing Central and South American shortfall.

Challenges

Central and South America faces persistent product supply deficits due to a lack of refining capacity and despite abundant upstream potential. The region is set to deliver strong production growth in countries like Brazil, Guyana and Suriname. However, political instability and underinvestment continue to weigh heavily on downstream infrastructure. Refinery throughput remains stagnant, with many facilities ageing or idle. Regional demand for refined products is growing, but with limited new investment in domestic capacity, import reliance is rising steadily. Without substantial investment or improved operational performance, the refining sector will remain a bottleneck in an otherwise resource-rich region.

Central and South America refinery runs, demand and net product balances, 2012-2030



Africa

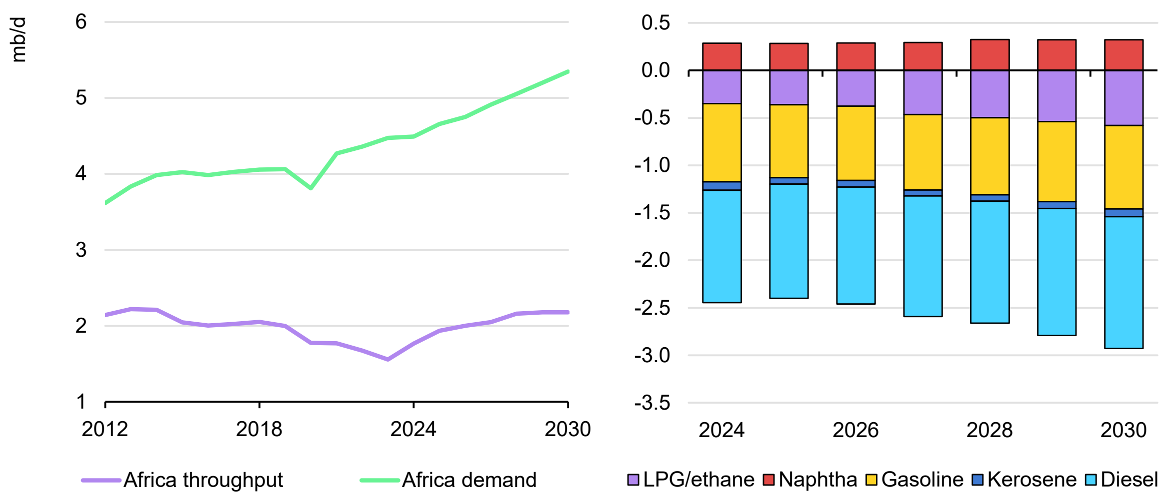
Africa's refining landscape is undergoing a structural transformation, with major capacity expansions underway and several small to medium-sized projects advancing across key markets. The commissioning of the independent 650 kb/d Dangote refinery in Nigeria marks a turning point for West Africa's product balances. After years of delays, the continent's largest refinery started processing crude in H1 2024. Crude imports averaged around 400 kb/d by Q1 2025, including cargoes from the United States, Brazil and Angola. While operational issues, problems securing domestic crude allocations and delays in the integration of secondary units persist, throughput is expected to stabilise at above 70% of capacity by late 2025. Once fully online, the facility will significantly reduce Nigeria's fuel import needs and reconfigure regional and Atlantic Basin product flows. Overall, Africa's refining capacity is projected to increase by 220 kb/d between 2024 and 2030.

Alongside this flagship project, **Nigeria** is working to revive its state-owned refineries, with limited success thus far. The 210 kb/d Port Harcourt complex saw its older 60 kb/d crude unit restart in December 2024 after more than a decade of inactivity. However, processing proved short-lived and the refinery is not currently operating. Another 150 kb/d CDU at the same site is under rehabilitation and could potentially come online during 2026. Similarly, the 125 kb/d Warri refinery briefly resumed partial operations in late 2024, but is now back under maintenance pending a potential restart next year. Lastly, the 110 kb/d Kaduna refinery is still slated for rehabilitation, but unlikely to re-enter commercial operations before early 2027 and probably much later. Together, if successful, these efforts could lift Nigeria's total operational capacity towards 1 mb/d by the end of the decade. Elsewhere in West Africa, we have included small domestically-focused projects in Ghana and in Congo, which are progressing after numerous delays.

Algeria's refining capacity will also expand with the construction of a new 110 kb/d refinery at Hassi Messaoud. This much delayed project is now estimated to start-up in 2028. Algeria's older facilities at Skikda, Algiers and Oran were previously modernised to improve product quality.

In East Africa, **Uganda** has progressed plans for a 60 kb/d greenfield refinery to process Lake Albert crude. In April 2025, a lead investor was secured and key agreements on government participation and feedstock supply are being finalised, with commissioning targeted for around 2027. However, in the absence of more concrete construction plans, we have excluded this project from the forecast.

African refinery runs, demand and net product balances, 2012-2030



Crude and product balances

Africa's net crude exports are set to contract by 350 kb/d to 4.6 mb/d by 2030. This shift is driven primarily by the ramp-up of regional refining capacity – most notably the 650 kb/d Dangote refinery in Nigeria, along with smaller projects in Algeria, Ghana and Congo. These latter facilities are designed to process locally produced crude, thereby reducing the region's exportable surplus. Thus far, higher African crude runs have been met by increased imports, as the Dangote refinery has focused on acquiring and processing the most cost effective grades and not simply acquire relatively expensive domestic crude cargoes.

Despite ambitious plans to expand domestic refining capacity, regional demand growth will outpace product supply. Strong demand growth of 860 kb/d, of which 630 kb/d is for refined fuels and 230 kb/d is LPG, will lift the continent's product imports requirement significantly. The region's refined product deficit is projected to widen by 230 kb/d to 2.3 mb/d by 2030. Gasoline and diesel will remain the products with the largest shortfalls, with diesel alone accounting for 1.4 mb/d. Africa's 320 kb/d surplus of naphtha is insufficient to offset the broader product import requirements. Furthermore, the ramp-up of multiple clean cooking initiatives have led to a large demand increase for LPG, with deficits set to nearly double over the forecast period to 570 kb/d.

Challenges

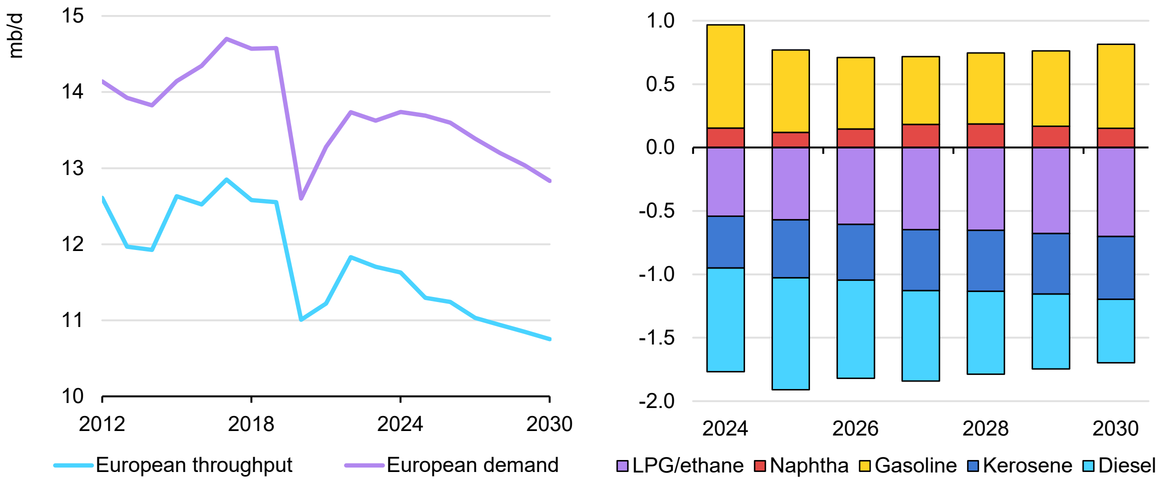
Africa is losing ground in its fight to move towards greater refined products self-sufficiency. Despite refining sector expansions, with several large projects underpinned by national energy security strategies, demand growth will outpace domestic refined product supply. Furthermore, implementation risks remain high, and even if the net forecast additions – alongside the ramp-up of large already-commissioned projects – are delivered, Africa will still only be a marginal contributor to global refining growth in the coming decade. Without substantial acceleration in refinery projects or improved utilisation rates, Africa will continue to rely heavily on refined product imports to meet rising demand, especially for transport fuels.

Europe

Total product demand in Europe, (including OECD and non-OECD Europe), is expected to see the steepest regional decline at just over 900 kb/d, to 12.8 mb/d by 2030. Refinery runs are projected to drop nearly 900 kb/d, broadly tracking the fall in demand. Total capacity of 14.5 mb/d is only just above demand for refined products; however, the region's high-cost structure and substantial but uneven product imbalances leave capacity at risk of closure. We expect capacity at risk to rise by 650 kb/d, to 1.6 mb/d.

Arguably, the region's heavy reliance on middle distillate imports have lent support to European diesel and jet fuel cracks that encourage refineries to maximise middle distillate production at the expense of other products. However, the shift in demand away from diesel towards gasoline that has been evident since 2019 has shrunk the net diesel import requirement, particularly for EU nations. The forecast decline in diesel demand will see this imbalance shrink further in the coming years, albeit the need to import kerosene will increase in parallel.

European refinery runs, demand and net product balances, 2012-2030



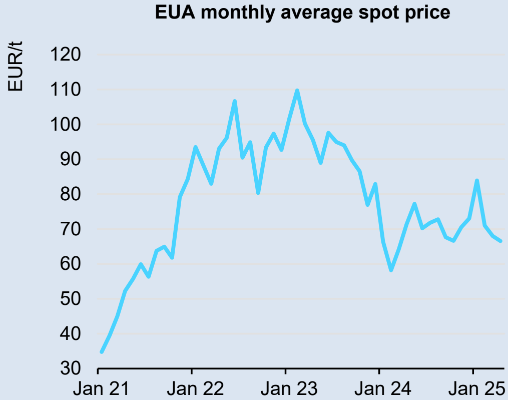
OECD Europe's refining sector remains in structural decline, with major capacity additions since 2011 limited to Repsol's 110 kb/d expansion in 2011 at Cartagena plant in Spain and Socar's 190 kb/d Star refinery in Türkiye in 2019. Against this backdrop, there has been an unbroken trend of rationalisation that has accelerated under mounting economic and policy pressures. Announced closures for the region total of 370 kb/d by 2030, with the potential for substantially more in the latter part of the decade. No expansions or greenfield projects are expected over the forecast period. Beyond investment to meet maintenance and regulatory requirements, or pursue low-carbon fuels and hydrogen integration, the broader stagnation of European refining investment is clear.

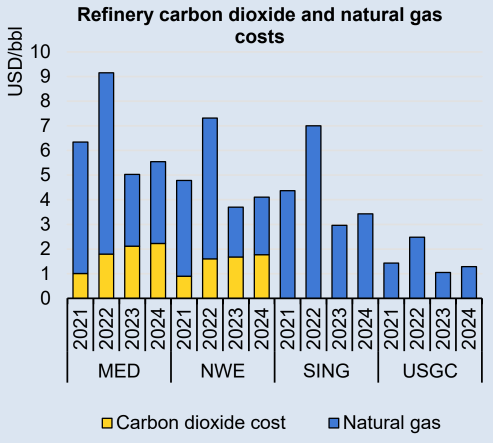
This year marks the region's largest annual capacity reduction since 2012, with over 370 kb/d of confirmed shutdowns. Shell has closed the 150 kb/d Wesseling section of the Rheinland-Palatinate refinery in Germany, BP is set to shut an 80 kb/d unit at its 240 kb/d Gelsenkirchen refinery before year-end and the 140 kb/d Petroineos Grangemouth facility in the United Kingdom was shuttered in April this year. These closures follow a string of earlier site conversions or shutdowns – including TotalEnergies' 100 kb/d Grandpuits and ExxonMobil's 110 kb/d Slagen in Norway in 2021, Eni's 120 kb/d Livorno, in 2024. Several planned biofuel conversions, such as Grandpuits, Wesseling and Venice, are proceeding, but these involve shutting traditional CDU capacity and thus reducing the region's total crude processing footprint, as well as conversion capacity which cuts light product yields. Moreover, planned investments in renewable hydrogen projects have also stalled in recent months as companies re-evaluate their strategies.

Regulatory impacts on the European refining system

European refiners face a structurally challenging future as carbon compliance costs rise and as European Union's "Fit for 55" policy ambitions intensify. Chief among these is the EU Emissions Trading System (EU-ETS), which has significantly increased operating costs for refineries since the reduction in free emissions allowances, which began in 2013. The price of EU Allowances (EUA) – the permits required for emitting one tonne of CO_2 under the EU-ETS – has increased from approximately EUR 30/t in 2021 to around EUR 70/t today. This surge represents a significant cost burden for European refiners, translating into a direct carbon cost of around USD 1-2/bbl at current market prices. Historically, the refining sector benefitted from free EUA allocations, calibrated to reward the most carbon-efficient installations and penalise higher-emitting facilities, thereby incentivising emissions reductions. However, these free allocations are being progressively phased out. By 2025, refinery allocations will be down 20% relative to 2020 levels, and by 2030 they are expected to decline by over 40%. This erosion of free allowances will increase the effective carbon cost faced by refiners and may accelerate rationalisation and investment shifts across the sector.

European Union carbon pricing and global refinery costs





Note: MED is Mediterranean, NWE is Northwest Europe, SING is Singapore, USGC is United States Gulf Coast. For further details see the IEA refining margins methodology.

Sources: IEA analysis based on prices from *Argus Media Group, All rights reserved.*

This rising carbon cost is compounded by elevated natural gas prices, which inflate hydrogen production costs used in desulphurisation processes. The combined cost of natural gas and carbon allowances for Mediterranean refiners averaged nearly USD 9/bbl in 2022 following Russia's invasion of Ukraine. While prices have since eased, the episode exposed the sector's vulnerability to fuel and carbon market volatility, prompting modest but growing investment in green hydrogen and a greater focus on energy efficiency measures.

At the same time, the European Union's inclusion of maritime transport in the EU-ETS as of 2024 generates additional demand for credits which will boost costs for integrated refining and shipping supply chains. Under the new regime, 100% of emissions from intra-EU voyages and 50% from voyages beginning or ending outside the European Union are now within the scope of compliance. This shift raises freight costs, lowers the refinery netback value of exports and increases the delivered cost of crude.

Furthermore, the expansion of Sulphur Emission Control Areas (including the Mediterranean from 2025), combined with IMO 2020, has pushed refiners to optimise yields for marine gasoil (MGO) and VLSFO. This benefits complex, coastal refineries with desulphurisation capacity and strong middle distillate production, while pressuring simpler plants reliant on high sulphur fuel oil (HSFO) output. In parallel, EU measures such as FuelEU Maritime and the inclusion of shipping in the EU-ETS are expected to erode long-term demand for petroleum-based marine fuels, encouraging investment in biofuel blending, green hydrogen and low-carbon refining upgrades.

Crude and product balances

OECD Europe's crude oil balance will remain in a significant deficit through 2030, sustained by declining regional production and despite easing crude runs. Crude throughputs will drop by nearly 500 kb/d, while crude import requirements will narrow by only 200 kb/d to 5.4 mb/d by the end of the forecast period. As Africa's crude balance tightens, European refiners will be required to rely more on Middle East and Latin American crude imports.

OECD Europe's refined product deficit is expected to remain flat, as both product output and demand declines. Falling gasoline exports and increasing kerosene import needs outpace the shrinking diesel requirements as regional demand contracts by 560 kb/d by 2030. The diesel deficit contracts from 930 kb/d in 2024 to 660 kb/d by the end of the decade.

Challenges

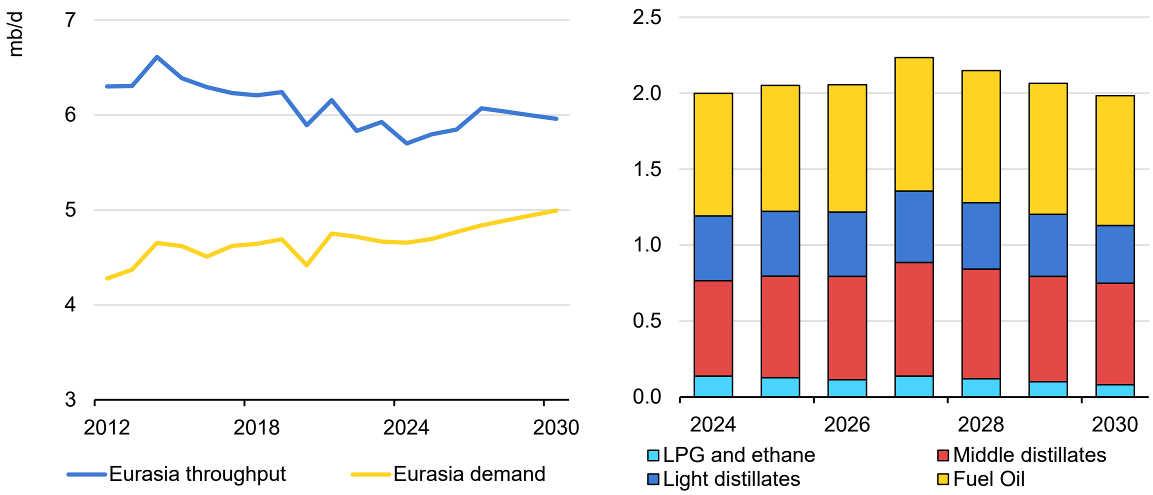
A growing number of European refineries are expected to either close or undergo major transformation by 2030. Most facilities will need to pivot toward an increased share of biorefining, or low-carbon fuel production, to remain operational. Without such adaptation, some face the risk of closure. Operators are already planning to scale back crude distillation, while others explore integration of e-fuels and hydrogen. Rising competition from Middle East and African refineries, which has started to limit gasoline exports to West Africa, alongside declining road fuel demand, is accelerating this shift.

Eurasia

Euraisan refining capacity is expected to grow by a modest 180 kb/d over the 2024-30 period, primarily through small-scale expansions and continued modernisation rather than new greenfield developments. This incremental growth reflects both the structural limitations of the regional refining sector and as well as the challenges posed by sanctions, military conflict, ageing assets, and constrained investment flows.

In **Russia**, the most notable recent addition was the 70 kb/d Ust-Luga condensate splitter, which came online in 2024, boosting the site's processing capacity to 220 kb/d. Forteinvest's 60 kb/d expansion at the Afipsky refinery is due online in Q2 2025, while Yug Rusi's 50 kb/d expansion at the Novoshakhtinsk refinery is scheduled for Q1 2026.

Eurasia refinery runs, demand and net product balances, 2012-2030



Russia has not built a major greenfield refinery in over a decade. In part, this reflects the government's desire for companies to prioritise refinery upgrades. A multi-year modernisation programme has driven a broad wave of investment in secondary units across major sites. These efforts aim to raise conversion rates and boost light product yields. It will also align Russia's refining output slate with domestic and export product specifications. While these investments have only a marginal impact on net distillation capacity, they are critical to sustaining Russia's role as a major refined product exporter.

Elsewhere in Eurasia, refinery projects remain sparse. **Kazakhstan** is advancing a proposed 150 kb/d refinery, though it is still in the feasibility stage and not included in this outlook. Similarly, **Georgia** has broken ground on the Kulevi refinery, but the timing of initial production from the 80 kb/d project is uncertain.

Crude and product balances

The Eurasia region, led by Russia, maintains a substantial net export position in crude oil, though volumes decline slightly over the forecast period. By 2030, total crude exports are projected to fall by nearly 270 kb/d from 2024's level to 7 mb/d. This modest contraction reflects stagnating upstream output amid sanctions on Russia, investment uncertainty, and logistical constraints, even as domestic refinery upgrades modestly lift regional crude runs.

Eurasia will also maintain its refined product surplus at close to 2 mb/d by 2030, supported by gradual improvements in refinery efficiency and higher runs enabled by modernisation efforts. Diesel, naphtha and fuel oil remain the dominant export streams. Altogether, Eurasian crude oil and product exports contract by 300 kb/d over the forecast period but remain robust at 9 mb/d in 2030, reaffirming the region's role as a key supplier of crude and refined products to global markets.

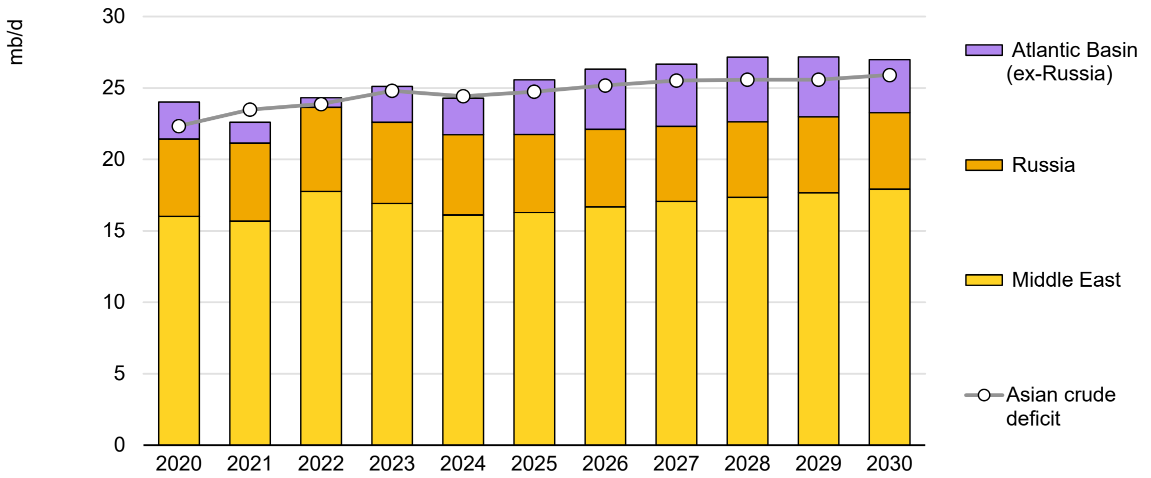
Challenges

The Eurasian refining sector remains constrained by geopolitical and operational headwinds. Sanctions have slowed equipment procurement and hindered financing for ongoing modernisation, while security risks (including drone strikes on Russian facilities) have temporarily curtailed some operations. The risks that secondary sanctions are imposed on Russian crude and product exports would further complicate the regional outlook. Against the backdrop of steady, upstream output, (in line with this *Report's* assumption that production remains in line with the 31 May 2025 OPEC+ agreement), modestly higher Russian runs lower crude and condensate exports by 270 kb/d by 2030. Although Russian product exports continue to expand, supported by refinery efficiency gains and increased diesel and fuel oil output, sustaining this surplus will require high utilisation rates amid ageing infrastructure and limited foreign investment. Outside Russia, the lack of projects reflect the broader challenge of attracting investment into the sector.

East of Suez

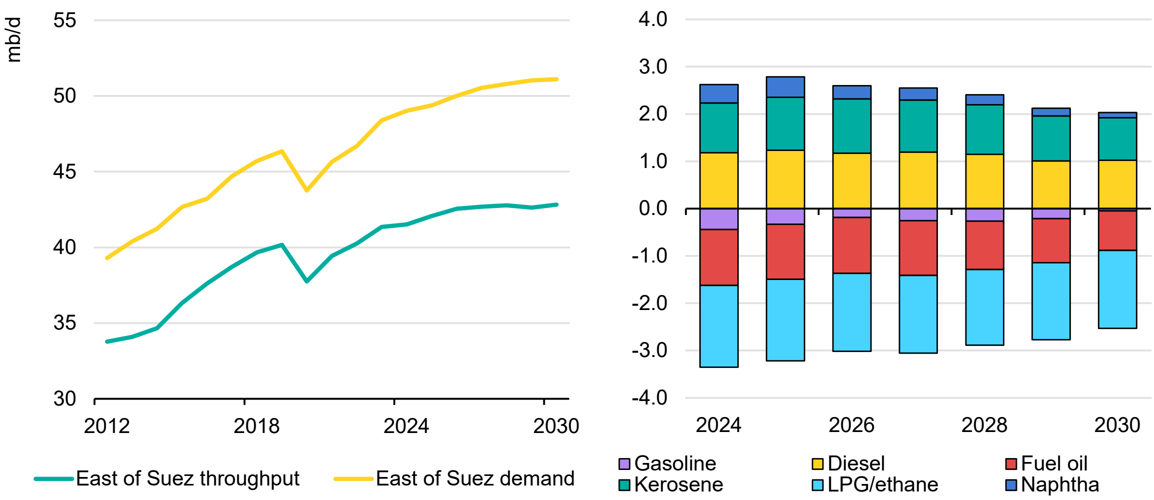
Refining capacity East of Suez is set to expand by a robust 2.7 mb/d by 2030, driven by gross additions exceeding 3.4 mb/d, of which India and China will account for nearly 1 mb/d each. India's growth is driven by large-scale projects, such as Panipat, Barmer and Numaligarh, that are all aimed at meeting rising domestic fuel demand. China's capacity increase is underpinned by world-scale petrochemical-focused refineries, including Yulong, Huajin and Fujian.

Global crude flows to meet Asian crude deficit, 2020-2030



However, refining throughput across the region will increase by just 1.3 mb/d – just behind the 1.4 mb/d rise in refined product demand that marginally increases the product supply deficit. More broadly, including non-refined products, total demand growth of 2.1 mb/d is lifted by LPG and ethane growth of 1.2 mb/d while crude oil burn drops by 540 kb/d as Middle East countries push towards gas and renewables in the power sector.

East of Suez refinery runs, demand and net product balances, 2012-2030



Utilisation rates are expected to fall by 1.6 percentage points to 78.3%, with significant underutilised capacity emerging, particularly in China. Despite adding nearly 1 mb/d of integrated petrochemical-oriented refining capacity, China will see refinery runs increase by just 250 kb/d due to weakening domestic demand for transportation fuels. In the Middle East, capacity growth will moderate after the recent wave of megaprojects, but targeted expansions in Bahrain, Iran and Iraq will still deliver 560 kb/d of net additions. By 2030, the Middle East is expected to contribute an additional 300 kb/d to global refined product supply, further consolidating its role as a key export-oriented refining hub.

Middle East

Following a period of rapid refining capacity expansion from 2020 to 2024 – during which the Middle East added over 2.2 mb/d of net capacity, the region's pace of growth is set to slow. However, strategic investments remain firmly in place through the forecast horizon, with a continued focus on regional fuel security, export competitiveness and condensate processing. By 2030, we expect an additional net 560 kb/d of refining capacity, split almost equally between crude distillation and condensate splitting additions.

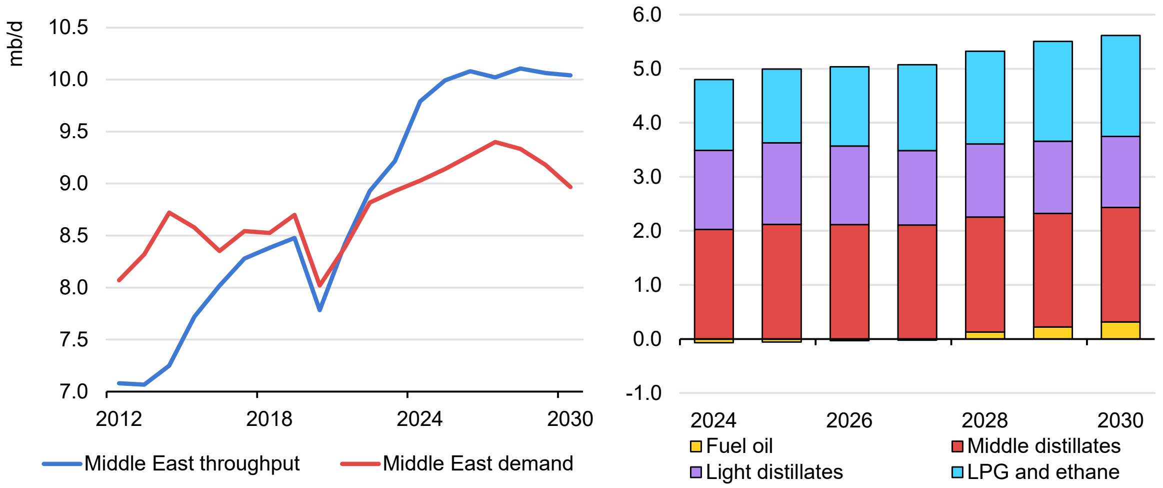
In **Bahrain**, the ongoing Bapco Modernisation Program at the Sitra refinery will add a new 225 kb/d CDU that replaces an older 110 kb/d unit. Associated upgrading units are scheduled to be fully commissioned by Q1 2026, enabling higher throughput and improved product quality, with the site expected to focus more on diesel and jet fuel for export.

Iran's National Iranian Oil Company is pursuing two capacity-enhancing projects. The fourth 120 kb/d train of the Persian Gulf Star condensate splitter is set to be commissioned in Q4 2025. This will be followed by the launch of the 60 kb/d Siraf condensate splitter due online in Q2 2026. Together, these projects will bolster Iran's output of gasoline and other light products, while increasing flexibility in condensate processing.

Oman will see a modest capacity boost from the final 30 kb/d tranche of its Duqm refinery project, due online in H2 2025. Following the inauguration of the export-orientated plant in late 2023, this addition marks the completion of the project and will support further product exports, particularly to Africa and Asia.

Iraq's South Refineries Company is working to bring online the new 100 kb/d Dhi Qar refinery, which we assume will occur in 2028. A further two 70 kb/d expansion projects, at Missan and Diwaniya, are also included before 2030. These projects will reduce gasoline and diesel import dependence in Iraq and meet growing domestic demand, particularly in the transport and power sectors. Several other projects aimed at raising the country's yield of light and middle distillates will also be delivered, lowering fuel oil output, which remains elevated.

Middle East refinery runs, demand and net product balances, 2012-2030



Crude and product balances

The Middle East will remain a dominant exporter of both crude oil and refined products over the forecast period. Net crude and product exports are projected to rise by 2.7 mb/d to reach 23.7 mb/d by 2030. Growth is driven by steady upstream expansion and increased refining throughput as major projects like Duqm and Jazan ramp up to full utilisation. Net crude oil exports are forecast to grow by 1.8 mb/d by 2030, underpinned by medium and heavy crude production increases in Saudi Arabia, Iraq and the UAE and the 540 kb/d decline in regional use of crude in power generation by 2030. Net product exports will increase by 860 kb/d, led by LPG as rising regional NGLs production boosts exports by 560 kb/d. Declining domestic use of fuel oil lifts exports by 380 kb/d by 2030, while diesel exports gains 120 kb/d. Gasoline and naphtha net exports decline by 150 kb/d, reflecting strong domestic consumption outpacing regional supplies and the shift in refining yields toward diesel and jet fuel.

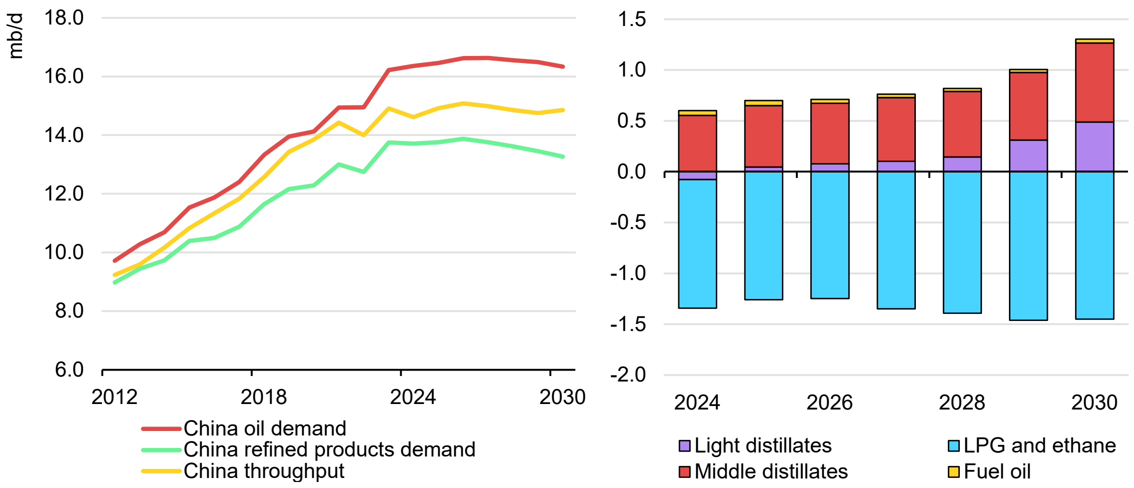
Challenges

While the pace of expansion has slowed compared to the previous five-year period, the Middle East remains a key source of capacity growth, consolidating its role as a refined product export hub while processing heavier and sourer crude grades through upgraded configurations. The region's strong demand growth will weigh on light distillate and jet fuel export volumes, while increasing supplies of medium and heavy crude should start to reward recent investments in upgrading of existing capacity.

China

China’s refining landscape will continue to evolve through 2030, albeit under tighter regulatory scrutiny and more deliberate structural adjustments. The country’s maturing refining sector will increasingly focus on adapting to domestic energy transition policies, including electrification, efficiency gains and rising non-oil alternatives. Following a surge of large-scale additions over the past decade – which includes Guangdong Petrochemical, Shenghong Petrochemical and Zhejiang – the country’s installed capacity has risen to approximately 18.5 mb/d and will see that number swell to 19.5 mb/d by 2030. With Beijing signalling a capacity ceiling near 20 mb/d, future growth will rely heavily on complex, integrated refinery-petrochemical (crude-to-chemicals) hubs, which will be balanced by the closure of small, less efficient operations. Over the forecast horizon to 2030, China is expected to add 1.3 mb/d of new or expanded CDU capacity, while announced closures total approximately 400 kb/d.

Chinese refinery runs, product demand and net product balances, 2012-2030



The single largest addition will come from the 400 kb/d Yulong Petrochemical complex in Shandong province, which began trial runs in H2 2024. The site’s two 200 kb/d CDUs were commissioned in Q1 2025. However, crude processing rates are restricted pending the start-up of the refinery’s extensive petrochemical units. This world-scale facility exemplifies China’s shift toward vertically-integrated petrochemicals-focused refining systems. Also in 2025, Sinochem’s Quanzhou (60 kb/d), CNOOC’s Daxie expansion (130 kb/d), and Sinopec’s major Zhenhai Refining & Chemical expansion (240 kb/d) are due to start up, boosting capacity by over 400 kb/d in central and eastern China. In 2026, Saudi Aramco and Norinco’s 320 kb/d Huajin complex (Panjin II) is also expected to enter operations, forming a key pillar in Aramco’s downstream expansion into China. Further out, Sinopec's Qilu Petchem expansion (70 kb/d) and Sinopec/Fujian's Gulei Phase II project (320 kb/d) are scheduled for 2028 and 2030, respectively.

These follow the model of large-scale, crude-to-chemicals hubs that are central to China's refining strategy. These capacity additions underpin the rapid shift in Chinese refinery yields that is necessary to reinforce the country's pivot to petrochemical feedstock production and away from traditional transportation fuels. From current levels, we forecast that naphtha yields will increase by 3.6%, with a corresponding decline in gasoline yields. Similarly, kerosene yields are boosted by 1.2% at the expense of diesel.

Offsetting these additions, the government continues to push the closure of small, inefficient refineries in Shandong. Three independent "teapots" – Wudi Xinyue, Dongfang Hualong, and Shouguang Luqing – will shut between 2026 and 2028, accounting for 170 kb/d in lost capacity. Other closures include Sinochem's Daqing Zhonglan (50 kb/d) and CNPC's Dalian WEPEC site, which will retire two CDUs totalling 200 kb/d in 2025. These closures, while significant, are dwarfed by the scale and complexity of new capacity additions.

Crude and product balances

China will remain the world's largest net importer of crude through the medium term, rising from 10.5 mb/d in 2024 to 11 mb/d by 2030. This reflects both falling domestic crude output and refining throughput that increases from 14.6 mb/d to 14.9 mb/d over the same period. This marks a slowdown from the long-term trend of rapidly increasing crude imports.

Ethane and LPG imports are forecast to increase from 1.3 mb/d in 2024 to close to 1.5 mb/d by 2030. Naphtha imports will stabilise at close to 400 kb/d, with sharply higher domestic supply at the expense of gasoline production. Nevertheless, the contraction in domestic gasoline demand will boost the potential for exports towards the end of the decade. Despite the assumed shift to jet fuel production that will stabilise jet fuel exports at current levels, a decline in diesel demand of nearly 430 kb/d by 2030 lifts diesel exports from around 200 kb/d in 2024 to 450 kb/d by the end of the decade.

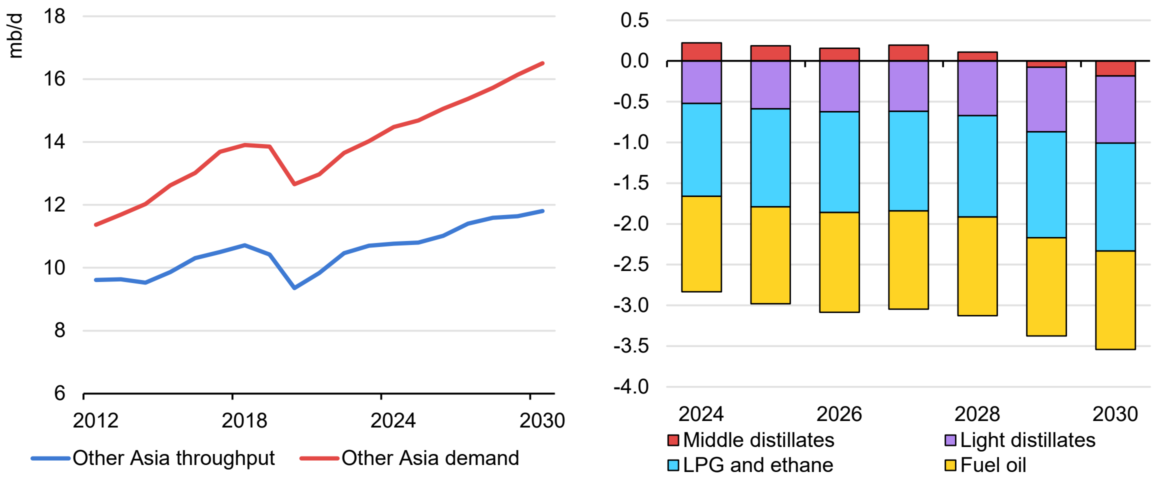
Challenges

Amid lower domestic transport fuel demand and continued refinery capacity additions, utilisation rates are expected to remain under pressure. In 2024, national refinery utilisation averaged around 79%. We forecast that it will drop further to 76% as transportation fuel demand declines. Historically, Chinese refiners have relied on clean product export quotas of around 40 Mt/yr (880 kb/d) to manage surplus output, with diesel and gasoline exports rising sharply in 2022-23 during periods of favourable margins. We assume these volumes will persist, as refiners seek to capitalise on rising import requirements in Southeast Asia. By the end of the decade, China's refining capacity could approach the 20 mb/d ceiling, with new additions requiring closures elsewhere. This reflects China's strategic pivot from transportation fuels towards large, integrated crude to chemical oriented complexes and rationalising its fragmented domestic-oriented capacity.

Other Asia

Refining capacity in Other Asia is expected to increase by 1.3 mb/d to reach 14.3 mb/d by 2030, driven almost entirely by large expansion projects in India. The region will see gross additions of 1.4 mb/d, partially offset by 170 kb/d of closures. While capacity growth in the region supports a forecast increase of 1 mb/d in refinery throughput, the region's older and smaller refineries are expected to struggle with increased competition from the Middle East. This is expected to weigh on regional crude runs growth, even though they remain insufficient to fully meet the 1.8 mb/d increase in regional refined product demand.

Other Asia refinery runs, demand and net product balances, 2012-2030



In contrast to China, where capacity growth is slowing amid policy caps and demand saturation, **India** continues to expand aggressively to meet rising domestic fuel demand and to cement its position as a regional refining and product export hub, accounting for nearly 1 mb/d of new capacity. Much of the new capacity prioritises chemical integration, reducing flexibility to meet diesel and gasoline demand. The country's capacity build-out is dominated by several refinery upgrades. The major expansion at the Panipat refinery will add 200 kb/d, with start-up scheduled for 2026. Elsewhere, capacity increases are expected at Numaligarh (+120 kb/d), Koyali (+80 kb/d), Bina (+60 kb/d). We also include the

180 kb/d increase at Nagapattinam, albeit not until 2030, alongside smaller upgrades at Mumbai, Digboi, and Kochi. The 180 kb/d Barmer refinery – the only greenfield project in the forecast – is scheduled to come online in 2026. The Barauni refinery will see a new 130 kb/d CDU installed to replace an old 70 kb/d CDU. Capacity additions in 2026 alone are expected to reach 680 kb/d, making it the single largest year for Indian refining growth in more than a decade.

Elsewhere in the region, additions are aimed at meeting local demand. **Indonesia** will add 100 kb/d of capacity at Balikpapan in 2026. In **Thailand**, Thai Oil is upgrading its Sriracha facility, replacing older crude units with a new 200 kb/d CDU by 2028, resulting in a net addition of 105 kb/d. **Brunei's** Hengyi Petrochemical refinery is advancing a second-phase 55 kb/d addition at its Pulau Muara Besar site, expected by 2029. **Mongolia** is also proceeding with its 30 kb/d greenfield Sainshand refinery, its first, scheduled for 2029.

Crude and product balances

Crude import requirements in Other Asia are set to rise by 1.4 mb/d to reach 9.9 mb/d by 2030 – making it the second largest import-dependent region globally, after China. India, the key growth driver, continues to pursue the acquisition of cost-advantaged crudes, replacing a swathe of Middle East grades with 1.8 mb/d of Russian crude imports in 2024, even as the Urals discount versus benchmark Dubai crude narrowed. The region's rising crude needs will be met through increased inflows from the Atlantic Basin as well as the Middle East, which benefits from its closer proximity and established contractual ties.

Despite this increase in regional capacity and rising crude imports, Other Asia is projected to face a growing refined product shortfall. Net product import requirements increase by 1 mb/d to 3.5 mb/d over the forecast period. Middle distillates see the largest shift, moving from a 220 kb/d surplus in 2024 to a 180 kb/d deficit by 2030. The regional gasoline deficit widens by around 110 kb/d in tandem with a 200 kb/d deterioration in naphtha balances, as petrochemical feedstock requirements surge. Elsewhere, clean cooking demand supports a 270 kb/d increase in LPG demand that pushes regional import needs above 1.2 mb/d by 2030. Fuel oil import dependence remains high, particularly in Singapore, the world's key marine fuel bunkering hub.

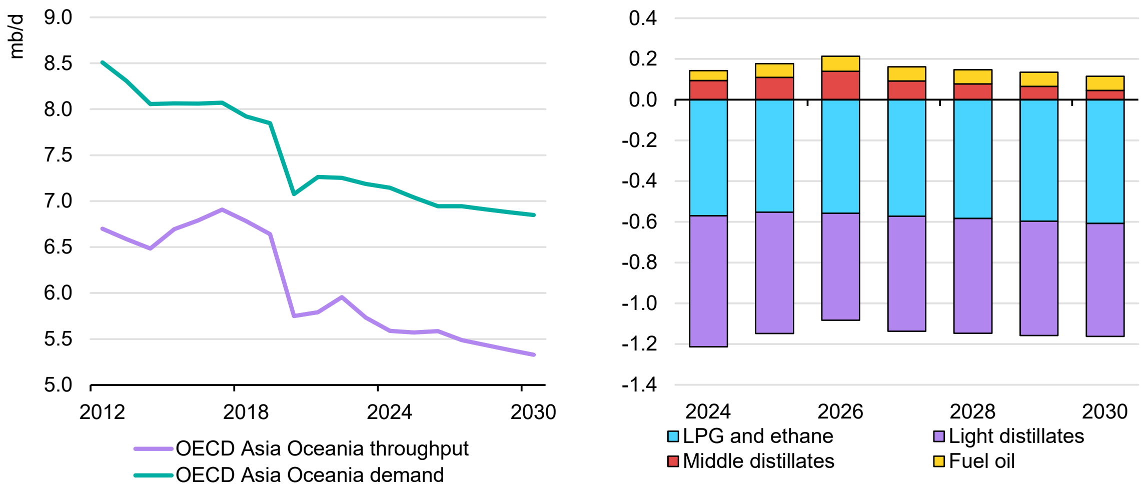
Challenges

Other Asia became the largest net importer of refined products in 2024, surpassing Africa. Strong demand growth, particularly for transport fuels and petrochemical feedstocks, continues to outpace refining output, driving product import needs up by nearly 1 mb/d by 2030. Despite steady capacity additions, primarily in India, the region faces persistent structural and rising import needs, with the crude import dependence also rising by 1.4 mb/d.

OECD Asia Oceania

OECD Asia Oceania distillation capacity is forecast to remain unchanged through 2030. This reflects a lack of announcements since the last regional closure of the 120 kb/d Yamaguchi refinery in Japan in 2024. However, the 300 kb/d decline in regional demand for refined products by 2030 will weigh on utilisation rates and we have lowered the crude throughput forecast by 260 kb/d accordingly. Both Korea and Japan are expected to see crude runs fall by a combined 240 kb/d through 2030, despite both countries retaining the need to import petrochemical feedstocks. The start of S-Oil's Shaheen petrochemical expansion at the Onsan plant in Korea will lift demand for feedstocks, even as transportation fuel demand contracts.

OECD Asia Oceania refinery runs, demand and net product balances, 2012-2030



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Crude and Product balances

Crude import requirements in OECD Asia Oceania are set to decline by 200 kb/d through 2030, as upstream output proves more durable than refined product demand and crude throughputs. Refined product import requirements remain stable, at around 650 kb/d, albeit heavily skewed towards LPG and naphtha – key feedstocks for Japan and Korea's petrochemical industries. Declining gasoline and diesel demand modestly lift the need to export surplus product, largely from Japan.

Challenges

Refining capacity in OECD Asia Oceania continues to struggle to compete with more modern and complex capacity elsewhere in Asia. Structural demand erosion, ageing assets and limited reinvestment compound the problem. Japan has paused the phase out of older capacity for now, while New Zealand has exited refining entirely. Although Korea maintains a robust, export-oriented refining sector, the region as a whole is shifting its focus toward petrochemical integration, energy efficiency and alternative fuels. These structural shifts are reinforcing OECD Asia Oceania's reliance on imported refined products.

Natural gas liquids

Global summary

Steady supply growth meets rising East of Suez demand

Growing global natural gas liquids (NGLs)[1] supply plays an outsized role in demand in our medium-term outlook. Rapidly increasing production from natural gas fields and associated gas feeds into key streams for petrochemical feedstocks, such as ethane, liquefied petroleum gas (LPG) and pentanes plus (C5+) or naphtha, as well as for gasoline blending, cooking and heating. Upstream oil projects involving lighter and gassier fields, especially in North America and the Middle East, will boost NGL output by 2.0 mb/d in the 2024-30 forecast, to 15.5 mb/d, accounting for nearly 50% of all global supply gains over the period.

The industry sends the vast majority of these flows to fractionation units – often centralised to cut costs – where they are separated into their components. However, around 10% of NGLs produced are used directly, mainly in refining and generally by blending into crude or bitumen.

Petrochemical producers have invested in new capacity to take advantage of growing availability of low-cost feedstocks, particularly ethane and LPG. Abundant LPG will also allow increased use for clean cooking in developing regions. Competition from these feedstocks will be a major factor in marginalising the role of the refining industry in supplying petrochemical demand to 2030.

Demand for ethane, an essential petrochemical feedstock, grows by 610 kb/d to 5.2 mb/d by 2030. The United States, the world's largest producer and consumer, will see continued production gains feeding both higher domestic demand as well as exports to Asian and European customers. Increased Middle East supply will mostly fuel expanding regional industrial use.

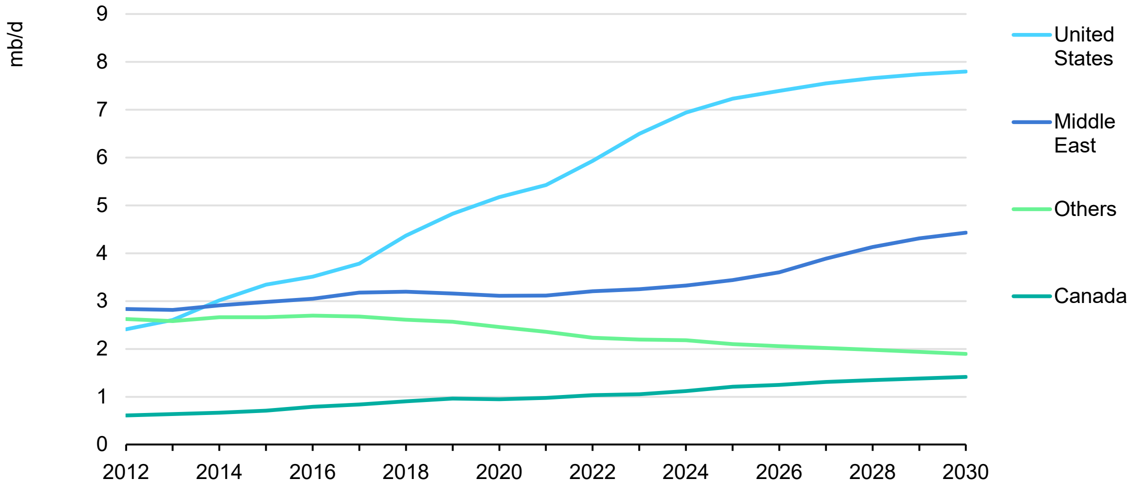
Overall LPG consumption will increase by 1.3 mb/d to 11.8 mb/d from 2024 to 2030, led by stronger demand in petrochemicals but also from rising use in heating and clean cooking. East of Suez demand expands by 820 kb/d to 6.6 mb/d, amounting to over 65% of the global gains, led by China and India. Atlantic Basin demand is driven by Africa and the United States. Canada, the United States and the Middle East will continue to dominate global LPG exports through to 2030.

[1] NGLs in this section does not include any condensate, including for OPEC+ countries

Supply growth driven by North America and Middle East

NGLs production has steadily ramped up over the past decade, reflecting burgeoning supply from unconventional reserves as well as upstream projects with lighter and gassier crude fields and wetter gas fields, especially in North America. The fractionation of NGLs at or near the wellhead yields ethane, propane, butanes and heavier fractions such as pentanes plus (C5+).

Global NGLs output, 2012-2030



From 2014 to 2024, global NGLs production grew by 4.3 mb/d to 13.6 mb/d. NGLs will rise by a further 2.0 mb/d to 15.5 mb/d in 2030, with average annual growth slowing to 2.3% over the forecast period, from 3.9% during the previous decade.

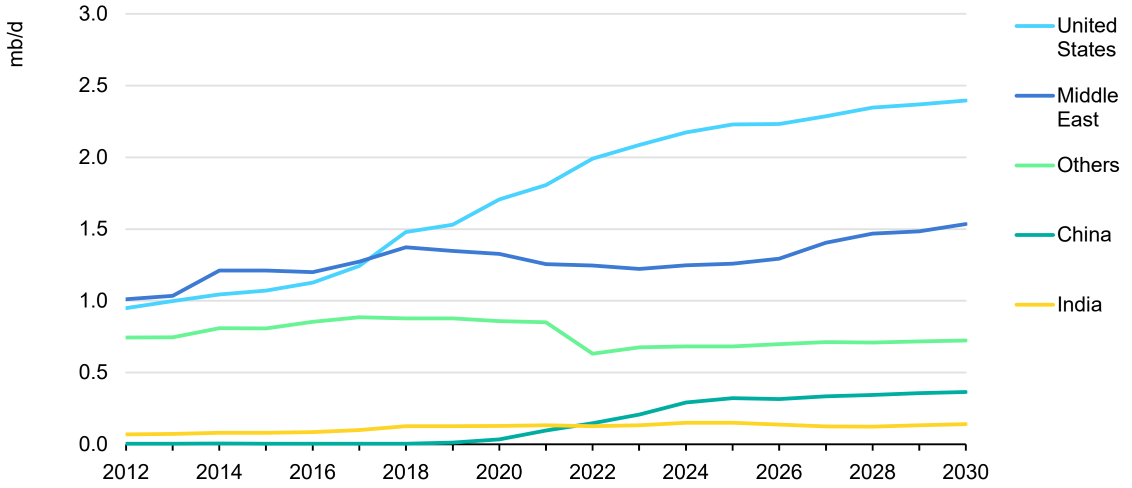
The United States, Saudi Arabia and Canada dominate global NGLs supply, with the three countries accounting for 84% of production today and rising to 88% by 2030. The United States alone held an overwhelming 51% market share, with production set to increase from 6.9 mb/d in 2024 to 7.8 mb/d in 2030 (+860 kb/d). Canadian output will rise by 300 kb/d, from 1.1 mb/d to 1.4 mb/d over the period. Despite increased supply in both countries, North America's share of global production remains unchanged through 2030 at around 60%. The Middle East will boost its share from 25% to 29% over the same period as output expands by 1.1 mb/d to 4.4 mb/d. Saudi Arabian production will rise to 2 mb/d by 2030, from 1.4 mb/d in 2024, supported by investments in natural gas and unconventional fields. Additional supply will also come from the buildout of natural gas and LNG projects in the UAE (+210 kb/d) and Qatar (+190 kb/d). By contrast, falling production in Asia and Europe (-110 kb/d, each) will cut their modest shares by 1%, to 3% in Asia and to 1% in Europe. Demand for ethane and LPG in the two regions will rise through 2030, however, increasing their import requirements.

Ethane markets

Global ethane markets maintain their US dependence on the United States

The global ethane market has a long-established supply-demand structure, with demand generally restrained by limited supply outside the United States and the Middle East. The United States dominates global output with an ample surplus of extractable volumes from low-cost and steadily growing natural gas streams. This makes it both the world's leading exporter and consumer of ethane, far exceeding other large consumers, including the Middle East, Canada, China and India. Middle Eastern countries are self-sufficient, using ethane from their own gas production. But China, Europe and India, and to a lesser extent Canada, are all dependent on imports of US ethane. Little will change in this configuration through 2030, though rising Middle East gas production will provide additional ethane to meet growth in local demand.

Global ethane demand, 2012-2030



Total ethane demand expands by 610 kb/d from 2024 to 2030, reaching 5.2 mb/d. The Middle East will lead demand growth, with project developments largely mirroring forecast increases in natural gas production. Regional demand increases by 290 kb/d to 1.5 mb/d in 2024-30, led by Saudi Arabia (+160 kb/d to 710 kb/d), Qatar (+100 kb/d to 250 kb/d) and the UAE (+40 kb/d to 230 kb/d). European demand will be boosted slightly by a new ethane cracker in Belgium towards the end of the forecast period, while use in Russia and India will remain largely unchanged. Chinese demand rises more slowly after a strong period of growth that lifted uptake to 290 kb/d in 2024. It will gain a further 75 kb/d over the forecast period, to reach 365 kb/d in 2030. In North America, US demand will increase by 220 kb/d to 2.4 mb/d by 2030, while Canada stagnates at 240 kb/d in the absence of new projects.

US ethane production is forecast to expand by 380 kb/d over the forecast, to reach 3.1 mb/d by 2030, boosting volumes available for export from 520 kb/d to 680 kb/d. Recently announced US export licencing obligations to China could impact this outlook. Growth in US exports offsets the deepening deficits in China and Europe by 2030. Rising production in Canada narrows the country's net shortfall by 70 kb/d to 25 kb/d in 2030.

Ethane storage capacity reached 162 mb in the United States in 2024, according to *Argus Media,* covering roughly 60 days of supply for this net exporter. Canadian storage of 26 mb covers about 108 days of demand and China's 11.5 mb (increasing to 12.8 mb in 2025) covers 39 days of current demand.

LPG markets

Abundant global LPG supply supports demand growth

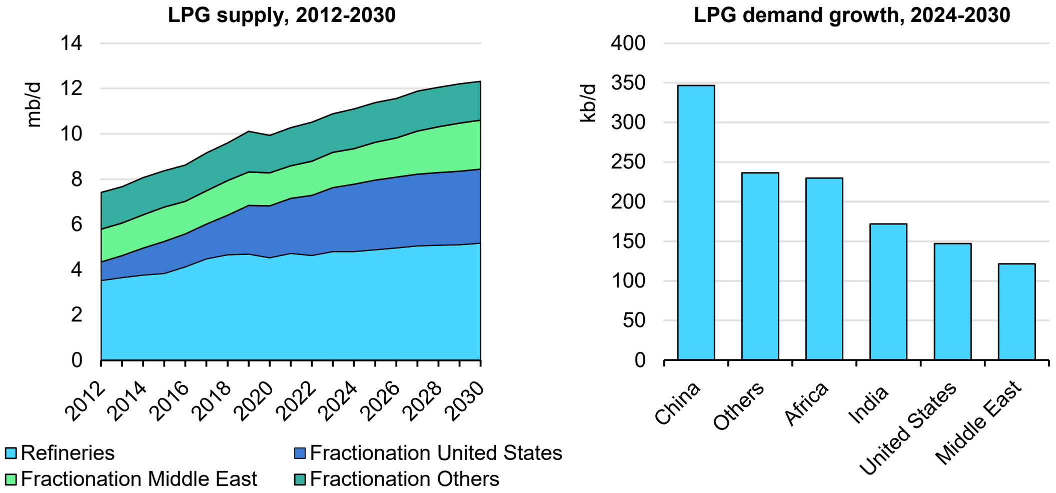
LPG supply remains abundant, weighing on prices relative to competing refined oil products and continuing to support strong demand growth as it has in recent years. Global LPG demand will rise by 1.3 mb/d to 11.8 mb/d from 2024 to 2030. Today, around 43% of LPG comes from refineries and the rest from NGL fractionation. LPGs include propane, normal butane and isobutane. LPG is used for cooking and heating (47%), petrochemical feedstocks (30%), industry (9%), transportation fuels (6%) and in the energy sector (6%). Expanding use in petrochemicals, cooking and heating drive demand growth through 2030.

Most incremental LPG supply comes from fractionation of NGLs, which is forecast to rise 850 kb/d to 7.1 mb/d by 2030. Gains are dominated by the Middle East (+600 kb/d to 2.2 mb/d) and North America (+400 kb/d to 4.1 mb/d). Saudi Arabia alone raises fractionation output by +390 kb/d to 1.0 mb/d. Refineries represent only 30% of incremental supply over 2024-30, increasing by 370 kb/d to 5.2 mb/d. Almost all this additional refinery supply arises from new capacity in China and India, while European output falls due to plant closures.

Markets East of Suez account for two-thirds of overall demand growth, gaining 820 kb/d over the outlook period to reach 6.6 mb/d. Of this, China's consumption increases by 350 kb/d to 2.7 mb/d, boosting its share of world demand from 22% to 23%. India follows with a 170 kb/d rise to 1.0 mb/d, underpinned by new petrochemical capacity and growing residential use, particularly in clean cooking.

The Middle East's appetite for LPG will increase 120 kb/d to 790 kb/d by 2030, mainly led by Saudi Arabia (+64 kb/d). In Africa, rapidly expanding use of LPG for heating and cooking boosts uptake by 230 kb/d to 860 kb/d. Demand in North Africa and West Africa each expand by 90 kb/d, to 540 kb/d and 220 kb/d, respectively, while use doubles in the rest of Africa to 100 kb/d. North American demand increases by 150 kb/d to 1.9 mb/d, almost entirely in the United States. European LPG consumption stagnates at around 1.1 mb/d through 2030 while Eurasian use will rise 11% to 920 kb/d by the end of the decade.

Global LPG supply and demand



Stable demand growth East of Suez, especially in Asia, continues to attract LPG supplies from major exporting countries. Available LPG for export from the United States and Canada reaches 2.6 mb/d, up 310 kb/d in the 2024-30 period, while Middle East exports grow 490 kb/d to just over 1.7 mb/d. Combined, these exporters account for 92% of all global exports, rising to 95% in 2030. The massive export flows partially help to offset widening deficits in Asia (from -2.6 mb/d in 2024 to -2.9 mb/d in 2030), Africa (-340 kb/d to -570 kb/d) and Europe (-480 kb/d t -600 kb/d). China's supply deficit increases by 110 kb/d to -1.1 mb/d, while the ASEAN deficit widens by 120 kb/d to -590 kb/d.

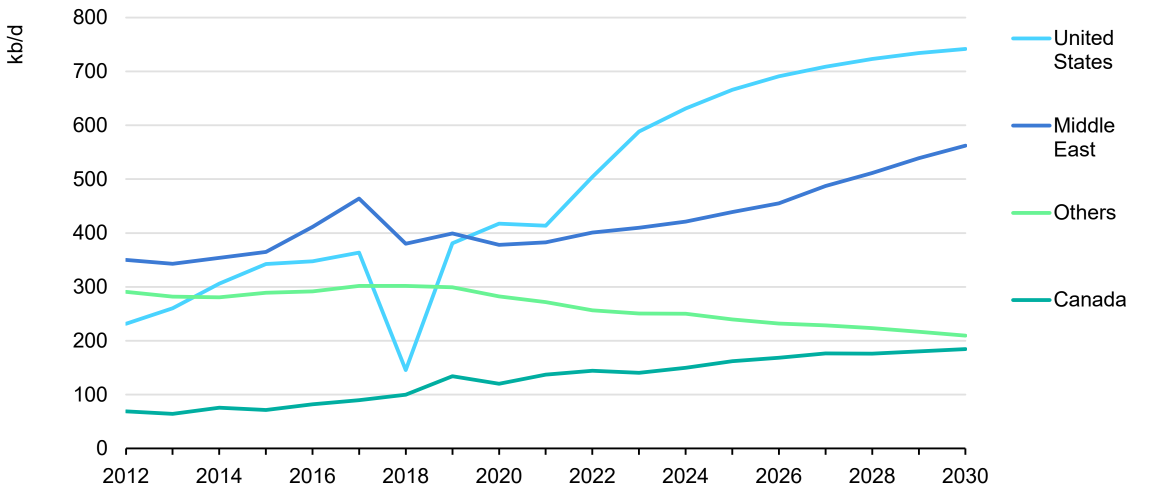
LPG storage capacity worldwide reached 709 mb in 2024, according to data from *Argus Media*, covering almost 70 days of global demand. North America accounts for 50% of the world's storage with capacity of 354 mb, of which 41% in the United States (295 mb), 6% (44 mb) in Canada and 2% in Mexico (15 mb). European storage amounts to 49 mb, equal to 45 days of demand. Capacity in OECD Asia Oceania was 71 mb in 2024, or 92 days of demand, with Japan accounting for over two-thirds of the region capacity at 48 mb, representing 121 days of demand while Korea holds 23%, or 16 mb, covering 49 days of demand. The Middle East accounts for 7% of global capacity, or 52 mb, covering 77 days of regional demand. China, the second largest user of LPG, holds 11% of world storage capacity, or 78 mb, equal to 33 days of demand. An additional 4.8 mb of capacity will be installed in China in the next few years, according to *Argus Media*. India will also raise capacity by 1.4 mb from 11 mb while Brazil will add 0.8 mb. European capacity will rise marginally (+0.4 mb).

C5+ markets

Increased NGL fractionation boosts Naphtha/C5+ supply

Global naphtha demand is met by supply from both refining and NGL fractionation that which produces a mix of molecules, referred to as C5+ and sometimes as natural gasoline, that are heavier than butane and are similar to naphtha. Most naphtha production comes from refineries (rising from 8.1 mb/d to 8.9 mb/d in 2024-30). Supply of C5+ is forecast to rise 250 kb/d to 1.7 mb/d by the end of the forecast. The output goes to refining and blending requirements but also directly for blending into the crude supply. For example, last year in the United States 45% of C5+ was transferred to the crude stream, around 30% went directly to refiners and blenders, while the rest was exported elsewhere as naphtha.

Global C5+ from fractionation, 2012-2030



Most of the world's C5+ is produced in the United States and Canada, where supply rises from 630 kb/d to 740 kb/d and from 150 kb/d to 180 kb/d, respectively, over 2024-30, for a combined gain of 140 kb/d. The Middle East accounts for another 140 kb/d of the global increase, reaching 560 kb/d by 2030.

Tables

Table 1
WORLD OIL SUPPLY AND DEMAND
(million barrels per day)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
OECD DEMAND										
Americas	24.0	24.7	25.0	24.9	25.0	24.9	24.9	24.7	24.5	24.4
Europe	13.1	13.6	13.5	13.5	13.5	13.4	13.2	13.0	12.9	12.7
Asia Oceania	7.3	7.3	7.2	7.2	7.1	7.0	7.0	7.0	6.9	6.9
Total OECD	**44.4**	**45.6**	**45.7**	**45.7**	**45.6**	**45.3**	**45.1**	**44.7**	**44.4**	**44.0**
NON-OECD DEMAND										
Eurasia	4.7	4.7	4.7	4.7	4.7	4.8	4.9	4.9	5.0	5.0
Europe	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
China	15.2	15.2	16.5	16.6	16.7	16.9	16.9	16.9	16.8	16.7
Other Asia	13.3	14.1	14.5	15.0	15.3	15.7	16.1	16.4	16.9	17.3
Latin America	5.9	6.2	6.3	6.4	6.5	6.6	6.7	6.8	7.0	7.1
Middle East	8.6	9.1	9.2	9.2	9.4	9.5	9.6	9.6	9.4	9.2
Africa	4.4	4.5	4.6	4.6	4.8	4.9	5.0	5.2	5.3	5.4
Total Non-OECD	**52.9**	**54.4**	**56.5**	**57.4**	**58.2**	**59.2**	**60.1**	**60.7**	**61.2**	**61.5**
Total Demand[1]	**97.4**	**100.0**	**102.2**	**103.0**	**103.8**	**104.5**	**105.1**	**105.4**	**105.6**	**105.5**
OECD SUPPLY										
Americas	24.4	25.8	27.5	28.3	28.9	29.0	29.3	29.3	29.2	29.2
Europe	3.4	3.2	3.2	3.2	3.3	3.3	3.1	3.1	2.9	2.7
Asia Oceania	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total OECD[2]	**28.3**	**29.5**	**31.1**	**31.9**	**32.6**	**32.8**	**32.8**	**32.7**	**32.5**	**32.2**
NON-OECD SUPPLY										
Eurasia	13.8	13.9	13.8	13.5	13.6	13.7	13.7	13.6	13.5	13.5
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.3	4.3	4.2
Other Asia	2.9	2.7	2.7	2.6	2.6	2.5	2.5	2.5	2.5	2.4
Latin America	5.3	5.7	6.2	6.4	6.8	7.2	7.3	7.7	7.8	7.6
Middle East	3.1	3.2	3.1	3.1	3.1	3.2	3.3	3.5	3.6	3.7
Africa	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.5	2.4
Total Non-OECD[2]	**31.7**	**32.3**	**32.7**	**32.6**	**33.1**	**33.5**	**33.8**	**34.3**	**34.3**	**33.9**
Processing gains[3]	2.2	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5
Global Biofuels	2.8	2.9	3.1	3.4	3.5	3.7	3.8	3.9	4.0	4.1
Total Non-OPEC	**65.0**	**66.9**	**69.4**	**70.3**	**71.6**	**72.4**	**72.8**	**73.4**	**73.2**	**72.7**
OPEC[4]										
Crude	25.4	27.7	27.4	27.2						
NGLs	5.3	5.5	5.5	5.5	5.7	5.9	6.3	6.5	6.7	6.9
Total OPEC	**30.7**	**33.1**	**33.0**	**32.8**						
Total Supply	**95.7**	**100.0**	**102.3**	**103.1**						
Memo items:										
Call on OPEC crude + Stock ch.[5]	27.1	27.6	27.3	27.2	26.5	26.2	26.1	25.5	25.6	26.0

1 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply. Includes biofuels.
2 Comprises crude oil, condensates, NGLs, oil from non-conventional sources and other sources of supply.
3 Net volumetric gains and losses in the refining process and marine transportation losses.
4 OPEC includes current members throughout the time series.
5 Total demand minus total non-OPEC supply and OPEC NGLs.

For the purpose of this and the following tables :
- OECD comprises of Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan,Korea, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, Norway, New Zealand, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, UK, US.
- OPEC comprises of Algeria, Congo, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, UAE, Venezuela.

Table 1a
WORLD OIL SUPPLY AND DEMAND: CHANGES FROM OIL 2024
(million barrels per day)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
OECD DEMAND									
Americas	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.8	1.0
Europe	0.0	0.0	0.2	0.3	0.3	0.3	0.3	0.4	0.4
Asia Oceania	0.0	0.0	-0.1	-0.1	-0.2	-0.2	-0.1	-0.1	-0.1
Total OECD	**0.0**	**0.0**	**0.2**	**0.2**	**0.3**	**0.6**	**0.8**	**1.0**	**1.2**
NON-OECD DEMAND									
Eurasia	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.1	0.1	-0.5	-0.8	-0.8	-0.9	-1.1	-1.2	-1.4
Other Asia	-0.1	-0.1	0.1	0.0	-0.1	-0.1	-0.1	-0.1	-0.1
Latin America	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.0	0.1	0.1
Middle East	0.2	0.2	0.2	0.1	0.2	0.3	0.3	0.3	0.2
Africa	0.1	0.1	0.2	0.3	0.2	0.2	0.3	0.3	0.3
Total Non-OECD	**-0.1**	**0.0**	**-0.4**	**-0.7**	**-0.8**	**-0.7**	**-0.9**	**-1.0**	**-1.2**
Total Demand	**-0.1**	**0.0**	**-0.2**	**-0.5**	**-0.5**	**-0.2**	**-0.1**	**0.0**	**0.1**
OECD SUPPLY									
Americas	0.1	0.1	0.2	0.1	-0.1	0.0	-0.1	-0.2	-0.3
Europe	0.0	0.0	0.0	-0.1	0.1	0.1	0.0	0.0	-0.1
Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total OECD	**0.1**	**0.1**	**0.1**	**0.0**	**0.1**	**0.1**	**-0.1**	**-0.2**	**-0.4**
NON-OECD SUPPLY									
Eurasia	0.0	0.0	0.0	-0.1	-0.2	-0.1	-0.2	-0.3	-0.3
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
China	0.0	0.0	-0.1	-0.1	0.0	0.1	0.1	0.2	0.2
Other Asia	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.3	0.4
Latin America	0.0	0.0	-0.1	0.0	-0.3	-0.4	-0.4	-0.4	-0.3
Middle East	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.1
Africa	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.1	-0.2	-0.3
Total Non-OECD	**0.0**	**0.0**	**-0.3**	**-0.4**	**-0.6**	**-0.5**	**-0.4**	**-0.4**	**-0.2**
Processing Gains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Global Biofuels	0.0	0.0	0.1	0.1	0.2	0.3	0.3	0.4	0.3
Total Non-OPEC	**0.1**	**0.1**	**0.0**	**-0.2**	**-0.4**	**-0.2**	**-0.1**	**-0.2**	**-0.2**
OPEC									
Crude	-0.5	-0.3							
NGLs	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2
Total OPEC	**-0.4**	**-0.3**							
Total Supply	**-0.3**	**-0.2**							
Memo items:									
Call on OPEC crude + Stock ch.	-0.3	-0.1	-0.2	-0.2	-0.1	-0.1	-0.2	0.0	0.1

Table 1b
WORLD OIL SUPPLY AND DEMAND - WEO Regions
(million barrels per day)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
DEMAND									
North America	24.3	24.6	24.5	24.6	24.5	24.4	24.3	24.1	24.0
Central and South America	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.4	7.4
Europe	14.3	14.2	14.3	14.3	14.2	14.0	13.9	13.7	13.5
Africa	4.5	4.6	4.6	4.8	4.9	5.0	5.2	5.3	5.4
Middle East	9.1	9.2	9.2	9.4	9.5	9.6	9.6	9.4	9.2
Eurasia	4.7	4.7	4.7	4.7	4.8	4.9	4.9	5.0	5.0
Asia Pacific	36.6	38.2	38.8	39.1	39.6	40.0	40.3	40.7	40.9
Total Demand[1]	**100.0**	**102.2**	**103.0**	**103.8**	**104.5**	**105.1**	**105.4**	**105.6**	**105.5**
NON-OPEC SUPPLY									
North America	25.8	27.4	28.3	28.9	29.0	29.3	29.3	29.2	29.2
Central and South America	5.7	6.2	6.4	6.8	7.2	7.3	7.7	7.8	7.6
Europe	3.3	3.3	3.3	3.4	3.4	3.2	3.1	3.0	2.8
Africa	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.5	2.4
Middle East	3.2	3.1	3.1	3.1	3.2	3.3	3.5	3.6	3.7
Eurasia	13.9	13.8	13.5	13.6	13.7	13.7	13.6	13.5	13.5
Asia Pacific	7.4	7.4	7.4	7.4	7.4	7.3	7.2	7.1	7.0
Total Non-OPEC	**61.7**	**63.9**	**64.5**	**65.7**	**66.3**	**66.6**	**67.0**	**66.8**	**66.1**
Processing gains[3]	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5
Global Biofuels	2.9	3.1	3.4	3.5	3.7	3.8	3.9	4.0	4.1
Total Non-OPEC Supply	**66.9**	**69.4**	**70.3**	**71.6**	**72.4**	**72.8**	**73.4**	**73.2**	**72.7**
OPEC[4]									
Crude	27.7	27.4	27.2						
NGLs	5.5	5.5	5.5	5.7	5.9	6.3	6.5	6.7	6.9
Total OPEC	**33.1**	**33.0**	**32.8**						
Total Supply	**100.0**	**102.3**	**103.1**						
Memo items:									
Call on OPEC crude + Stock ch.[5]	27.6	27.3	27.2	26.5	26.2	26.1	25.5	25.6	26.0

1 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply. Includes biofuels.
2 Comprises crude oil, condensates, NGLs, oil from non-conventional sources and other sources of supply.
3 Net volumetric gains and losses in the refining process and marine transportation losses.
4 OPEC includes current members throughout the time series.
5 Total demand minus total non-OPEC supply and OPEC NGLs.

Table 2
SUMMARY OF GLOBAL OIL DEMAND

	2023	2024	2025	2026	2027	2028	2029	2030
Demand (mb/d)								
Americas	24.98	24.94	24.97	24.93	24.86	24.73	24.55	24.36
Europe	13.46	13.51	13.50	13.40	13.20	13.02	12.88	12.68
Asia Oceania	7.24	7.21	7.10	7.00	7.01	6.98	6.95	6.92
Total OECD	45.68	45.67	45.57	45.33	45.07	44.73	44.37	43.95
Asia	30.95	31.63	32.01	32.58	33.01	33.34	33.70	33.96
Middle East	9.16	9.25	9.37	9.50	9.63	9.57	9.41	9.20
Americas	6.34	6.43	6.53	6.62	6.73	6.84	6.95	7.06
Eurasia	4.68	4.67	4.71	4.79	4.86	4.92	4.97	5.03
Africa	4.58	4.59	4.76	4.85	5.01	5.15	5.30	5.45
Europe	0.78	0.80	0.81	0.83	0.84	0.85	0.85	0.86
Total Non-OECD	**56.50**	**57.37**	**58.19**	**59.17**	**60.08**	**60.66**	**61.19**	**61.54**
World	**102.19**	**103.04**	**103.76**	**104.50**	**105.15**	**105.39**	**105.57**	**105.50**
of which:								
United States[1]	20.28	20.42	20.47	20.45	20.40	20.31	20.15	20.01
Europe 5[2]	7.52	7.57	7.51	7.42	7.28	7.17	7.07	6.93
China	16.48	16.63	16.73	16.89	16.95	16.89	16.81	16.66
Japan	3.29	3.14	3.05	3.01	2.97	2.94	2.91	2.89
India	5.45	5.64	5.75	5.92	6.08	6.25	6.45	6.66
Russia	3.54	3.49	3.50	3.55	3.58	3.59	3.60	3.60
Brazil	3.23	3.33	3.40	3.45	3.49	3.53	3.57	3.60
Saudi Arabia	3.64	3.66	3.67	3.69	3.62	3.49	3.29	3.05
Canada	2.45	2.38	2.39	2.36	2.34	2.31	2.29	2.26
Korea	2.45	2.54	2.52	2.47	2.51	2.51	2.51	2.51
Mexico	1.74	1.74	1.71	1.71	1.71	1.71	1.70	1.70
Iran	1.89	1.92	1.97	1.98	2.01	2.03	2.05	2.07
Total	**71.95**	**72.48**	**72.67**	**72.89**	**72.93**	**72.73**	**72.41**	**71.93**
% of World	70.4%	70.3%	70.0%	69.7%	69.4%	69.0%	68.6%	68.2%
Annual Change (% per annum)								
Americas	1.0	-0.2	0.1	-0.2	-0.3	-0.5	-0.8	-0.8
Europe	-0.7	0.4	-0.1	-0.8	-1.5	-1.4	-1.1	-1.6
Asia Oceania	-0.9	-0.5	-1.5	-1.4	0.0	-0.5	-0.4	-0.4
Total OECD	0.2	0.0	-0.2	-0.5	-0.6	-0.7	-0.8	-0.9
Asia	5.8	2.2	1.2	1.8	1.3	1.0	1.1	0.8
Middle East	1.1	1.0	1.3	1.4	1.4	-0.7	-1.6	-2.3
Americas	2.3	1.3	1.6	1.4	1.7	1.7	1.6	1.5
Eurasia	-0.7	-0.2	0.8	1.6	1.5	1.1	1.1	1.1
Africa	2.8	0.2	3.7	2.0	3.4	2.8	2.8	2.8
Europe	3.0	2.7	1.1	2.2	1.0	1.0	0.9	0.4
Total Non-OECD	3.8	1.5	1.4	1.7	1.5	1.0	0.9	0.6
World	2.2	0.8	0.7	0.7	0.6	0.2	0.2	-0.1
Annual Change (mb/d)								
Americas	0.26	-0.04	0.03	-0.04	-0.07	-0.12	-0.19	-0.18
Europe	-0.10	0.06	-0.01	-0.11	-0.19	-0.18	-0.14	-0.20
Asia Oceania	-0.07	-0.03	-0.11	-0.10	0.00	-0.03	-0.03	-0.03
Total OECD	0.10	-0.02	-0.09	-0.24	-0.26	-0.33	-0.36	-0.42
Asia	1.71	0.68	0.38	0.58	0.42	0.33	0.37	0.25
Middle East	0.10	0.09	0.12	0.13	0.13	-0.07	-0.15	-0.21
Americas	0.14	0.08	0.10	0.09	0.11	0.11	0.11	0.10
Eurasia	-0.03	-0.01	0.04	0.08	0.07	0.06	0.05	0.05
Africa	0.12	0.01	0.17	0.09	0.16	0.14	0.15	0.15
Europe	0.02	0.02	0.01	0.02	0.01	0.01	0.01	0.00
Total Non-OECD	2.06	0.87	0.82	0.98	0.91	0.58	0.53	0.35
World	2.16	0.85	0.72	0.74	0.65	0.25	0.17	-0.07

1 US figures exclude US territories.
2 France, Germany, Italy, Spain and UK.

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
OPEC									
Crude Oil									
Saudi Arabia	10.33	9.57	9.09						
Iran	2.55	2.99	3.34						
Iraq	4.45	4.27	4.31						
UAE	3.30	3.25	3.23						
Kuwait	2.71	2.66	2.55						
Nigeria	1.15	1.24	1.33						
Libya	0.99	1.16	1.07						
Algeria	1.01	0.97	0.91						
Congo	0.26	0.27	0.24						
Gabon	0.19	0.21	0.23						
Equatorial Guinea	0.08	0.06	0.06						
Venezuela	0.64	0.77	0.88						
Total Crude Oil	**27.66**	**27.43**	**27.24**						
of which Neutral Zone [1]	0.30	0.37	0.43						
Total NGLs[2]	**5.46**	**5.53**	**5.55**	**5.67**	**5.91**	**6.25**	**6.50**	**6.70**	**6.87**
Total OPEC[3]	**33.12**	**32.96**	**32.79**						
NON-OPEC[4]									
OECD									
Americas	25.78	27.46	28.30	28.89	29.03	29.27	29.27	29.24	29.18
United States	18.01	19.52	20.23	20.74	20.90	21.07	21.07	21.08	21.11
Mexico	2.01	2.10	1.97	1.84	1.74	1.60	1.47	1.40	1.29
Canada	5.76	5.83	6.09	6.30	6.38	6.59	6.73	6.75	6.77
Chile	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Europe	3.19	3.23	3.16	3.26	3.32	3.14	3.06	2.88	2.70
UK	0.84	0.73	0.70	0.71	0.72	0.68	0.66	0.64	0.60
Norway	1.91	2.02	2.00	2.03	2.06	1.92	1.88	1.74	1.61
Others	0.45	0.47	0.45	0.53	0.54	0.53	0.51	0.50	0.48
Asia Oceania	0.48	0.46	0.45	0.43	0.41	0.40	0.38	0.37	0.36
Australia	0.41	0.38	0.37	0.36	0.34	0.32	0.32	0.30	0.30
Others	0.07	0.07	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Total OECD	**29.46**	**31.14**	**31.90**	**32.58**	**32.76**	**32.80**	**32.72**	**32.50**	**32.23**
NON-OECD									
Eurasia	13.91	13.84	13.50	13.60	13.66	13.66	13.59	13.52	13.46
Russia	11.09	10.96	10.70	10.56	10.60	10.64	10.63	10.63	10.63
Azerbaijan	0.67	0.62	0.60	0.59	0.62	0.60	0.58	0.56	0.55
Kazakhstan	1.82	1.93	1.88	2.14	2.13	2.13	2.09	2.04	2.00
Others	0.33	0.33	0.32	0.31	0.30	0.30	0.29	0.28	0.27
Asia	6.90	6.94	6.95	6.99	6.97	6.88	6.84	6.74	6.62
China	4.18	4.27	4.34	4.39	4.43	4.39	4.34	4.26	4.20
Malaysia	0.56	0.56	0.54	0.54	0.54	0.51	0.49	0.48	0.47
India	0.72	0.70	0.70	0.71	0.69	0.68	0.68	0.67	0.67
Indonesia	0.63	0.63	0.60	0.59	0.58	0.59	0.60	0.61	0.62
Others	0.81	0.78	0.78	0.75	0.73	0.71	0.73	0.72	0.67
Europe	0.11	0.10	0.09	0.09	0.08	0.08	0.08	0.09	0.09
Americas	5.67	6.20	6.44	6.83	7.18	7.27	7.72	7.78	7.59
Brazil	3.12	3.49	3.44	3.73	3.92	3.82	4.07	3.93	3.77
Argentina	0.71	0.77	0.83	0.89	0.95	1.02	1.10	1.18	1.26
Colombia	0.76	0.79	0.79	0.76	0.73	0.71	0.68	0.65	0.63
Guyana	0.28	0.39	0.62	0.70	0.86	1.05	1.18	1.19	1.13
Others	0.80	0.77	0.77	0.75	0.71	0.68	0.69	0.82	0.80
Middle East	3.16	3.12	3.08	3.13	3.17	3.26	3.47	3.62	3.70
Oman	1.07	1.06	1.00	1.00	1.03	1.03	1.04	1.04	1.04
Qatar	1.80	1.81	1.84	1.88	1.91	2.00	2.21	2.37	2.46
Others	0.29	0.26	0.24	0.24	0.23	0.22	0.22	0.21	0.20
Africa	2.52	2.51	2.50	2.48	2.47	2.61	2.62	2.53	2.40
Angola	1.18	1.14	1.16	1.06	1.09	1.15	1.16	1.12	1.05
Egypt	0.60	0.60	0.57	0.53	0.51	0.49	0.46	0.44	0.42
Others	0.74	0.78	0.77	0.88	0.88	0.98	0.99	0.96	0.93
Total Non-OECD	**32.26**	**32.72**	**32.57**	**33.12**	**33.52**	**33.76**	**34.31**	**34.27**	**33.87**
Processing gains[5]	2.32	2.36	2.39	2.40	2.46	2.48	2.47	2.46	2.47
Global biofuels	2.90	3.14	3.40	3.52	3.68	3.79	3.91	4.02	4.08
TOTAL NON-OPEC	**66.93**	**69.36**	**70.26**	**71.61**	**72.43**	**72.83**	**73.41**	**73.25**	**72.65**
TOTAL SUPPLY	**100.05**	**102.32**	**103.05**						

1 Neutral Zone production is already included in Saudi Arabia and Kuwait production, split 50/50 between the two countries.
2 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. GTL in Nigeria, and non-oil inputs to Saudi Arabian MTBE.
3 OPEC data based on current membership throughout the time series.
4 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
5 Net volumetric gains and losses in refining and marine transportation losses.

Table 3a
SELECTED UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kb/d)	Start Year
OECD Americas			
US	Anchor	75	2024
US	Whale	80	2025
US	Shenandoah Phase 1	60	2025
US	Ballymore	75	2025
US	Leon/Castile	60	2025
US	Pikka Phase 1 (Alaska)	80	2026
US	Shenandoah Phase 2	60	2027
US	Vito Infill	30	2027
US	Sparta	90	2028
US	Willow (Alaska)	150	2029
US	Kaskida	80	2029
Canada	Mildred Lake Extension	140	2025
Canada	West White Rose	50	2026
Mexico	Trion	100	2028
Latin America			
Brazil	Atlanta FDS	50	2024
Brazil	Mero 3 (Mal. Duque de Caxias)	180	2024
Brazil	IPB (Maria Quitéria)	100	2024
Brazil	Bacalhau	220	2025
Brazil	Mero 4 (Alexandre de Gusmão)	180	2025
Brazil	Buzios 6 (P-78)	180	2025
Brazil	Buzios 7 (Alm. Tamandaré)	220	2025
Brazil	Buzios 8 (P-79)	180	2026
Brazil	Buzios 9 (P-80)	225	2027
Brazil	Buzios 10 (P-82)	225	2027
Brazil	Buzios 11 (P-83)	225	2027
Brazil	Maromba	60	2027
Brazil	Raia (BM-C-33)	125	2028
Brazil	Atapu 2 (P-84)	225	2029
Brazil	Gato do Mato	100	2029
Brazil	Sepia 2 (P-85)	225	2030
Guyana	Stabroek Phase 4 (Yellowtail)	250	2025
Guyana	Stabroek Phase 5 (Uaru)	250	2026
Guyana	Stabroek Phase 6 (Whiptail)	250	2028
Suriname	Block 58	220	2028
Eurasia			
Azerbaijan	Azeri Central East (ACE)	100	2024
Kazakhstan	Tengizchevroil FGP	260	2025
Kazakhstan	Kashagan Expansion Phase 1	25	2026
OECD Europe			
Norway	Eldfisk North	30	2024
Norway	Tyrving	30	2024
Norway	Balder X	40	2025
Norway	Johan Castberg	220	2025
Norway	Yggdrasil	100	2027
Denmark	Tyra Redevelopment	20	2024
UK	Penguins	40	2025
UK	Rosebank	60	2028
Middle East			
Saudi Arabia	Dammam Phase 1	25	2025
Saudi Arabia	Berri Expansion	250	2025
Saudi Arabia	Marjan Expansion	300	2025
Saudi Arabia	Zuluf Expansion	600	2026
Saudi Arabia	Dammam Phase 2	50	2027
Qatar	North Field Expansion East	240	2026
Qatar	North Field Expansion South	120	2028
Qatar	Bul Hanine Redevelopment	60	2027
Qatar	Al Shaheen Gallaf	90	2027
UAE	Belbazem	45	2024
UAE	Upper Zakum Expansion	200	2027
UAE	Lower Zakum Expansion	150	2027
UAE	Bab South East Expansion	130	2027
UAE	Umm Shaif Expansion	130	2027
Africa			
Senegal	Sangomar Phase 1 (SNE)	100	2024
Niger	Agadem Phase 2	50	2024
Nigeria	Bonga North	110	2029
Cote d'Ivoire	Baleine Phase 2	30	2024
Angola	Begonia	50	2025
Angola	Ndungu	40	2026
Angola	Agogo Phase 3	120	2027
Angola	Kaminho	50	2028
Uganda	Lake Albert (Kingfisher and Tilenga)	200	2026
Asia			
China	Liuhua	30	2024
China	Lufeng	20	2024
China	Wushi	30	2024
India	KG-DWN-98/2 (Cluster-2)	50	2024
Viet Nam	Lac Da Vang	30	2027
Viet Nam	White Whale	25	2027

Table 3b
SELECTED UPSTREAM PRE-SANCTION PROJECT
(Projects with procurement/engineering started and first oil potentially by 2030)

Country	Project	Peak Capacity (kb/d)	Sanction Year	Start Year
OECD Americas				
US	Tiber	120	2025	2029
US	Mad Dog Spar	40	2025	2027
US	Ocotillo	50	2026	2027
US	Winterfell extension	40	2025	2027
US	Perdido Spar	80	2026	2028
US	Whale Phase 2	70	2026	2028
US	Pikka Phase 2	40	2027	2030
Mexico	Polok-Chinwol	50	2026	2029
Mexico	Zama	150	2026	2030
Mexico	KMZ expansion	100	2026	2028
Latin America				
Guyana	Stabroek Phase 7 (Hammerhead)	150	2025	2030
Guyana	Stabroek Phase 8 (Longtail)	200	2026	2030
Brazil	BRC/CRT Revit	100	2025	2030
Brazil	Bacalhau Phase 2	100	2026	2030
OECD Europe				
Norway	Fram (extension)	40	2025	2028
Norway	Troll (extension)	30	2025	2029
Norway	Johan Castberg Phase 2	30	2026	2028
Norway	Aasgard	30	2026	2028
Norway	Balder/Ringhorne	30	2026	2028
Norway	Yggdrasil (extension)	40	2026	2029
Norway	Johan Sverdrup Phase 3	60	2025	2028
Norway	Wisting	80	2026	2029
UK	Cambo	50	2026	2029
Africa				
Cote d'Ivoire	Baleine Phase 3	100	2025	2028
Cote d'Ivoire	Calao	100	2026	2030
Ghana	Pecan	70	2026	2030
Namibia	Venus	150	2026	2030
Senegal	Sangomar Phase 2	80	2025	2029
Angola	Block 32	80	2025	2029
Asia				
Australia	Dorado	80	2027	2030
Eurasia				
Kazakhstan	Kashagan Phase 2	50	2026	2030

Table 3c
NON-OPEC SUPPLY: OIL MARKET REPORT AND WEO DEFINITIONS
(million barrels per day)

	Calculation	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil 2024 Report definitions										
NON-OPEC SUPPLY		**66.9**	**69.4**	**70.3**	**71.6**	**72.4**	**72.8**	**73.4**	**73.2**	**72.7**
Processing gains		2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5
Global biofuels		2.9	3.1	3.4	3.5	3.7	3.8	3.9	4.0	4.1
NON-OPEC PRODUCTION (excl. processing gains and biofuels)	**1**	**61.7**	**63.9**	**64.5**	**65.7**	**66.3**	**66.6**	**67.0**	**66.8**	**66.1**
Crude	2	50.4	51.9	52.0	52.8	53.2	53.2	53.4	53.0	52.3
of which: Condensate	3	4.3	4.5	4.6	4.5	4.5	4.6	4.7	4.8	4.9
Tight oil	4	8.7	9.6	10.2	10.6	10.6	10.8	10.9	11.0	11.2
Un-upgraded bitumen	5	2.0	2.0	2.1	2.1	2.1	2.2	2.3	2.4	2.4
NGLs	6	9.2	9.8	10.3	10.6	10.8	11.0	11.2	11.3	11.4
Syncrude (Canada)	7	1.3	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.6
CTL, GTL, kerogen oil and additives[1]	8	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9
World Energy Outlook definitions										
NON-OPEC PRODUCTION (excl. processing gains and biofuels)	=1	61.7	63.9	64.5	65.7	66.3	66.6	67.0	66.8	66.1
Conventional		**49.0**	**50.1**	**50.0**	**50.8**	**51.3**	**51.2**	**51.4**	**51.0**	**50.2**
Crude oil	=2-3-4-5	35.5	35.8	35.1	35.6	35.9	35.6	35.5	34.8	33.9
Natural gas liquids (total)	=3+6	13.5	14.3	14.9	15.2	15.4	15.7	15.9	16.1	16.3
Unconventional		**12.7**	**13.8**	**14.5**	**14.9**	**15.0**	**15.3**	**15.6**	**15.8**	**15.9**
EHOB (incl. syncrude)[2]	=5+7	3.3	3.4	3.6	3.6	3.6	3.7	3.9	3.9	3.9
Tight oil	=4	8.7	9.6	10.2	10.6	10.6	10.8	10.9	11.0	11.2
CTL, GTL, kerogen oil and additives[1]	=8	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9

1 CTL = coal to liquids; GTL = gas to liquids.

2 Extra-heavy oil and bitumen

Table 4
WORLD REFINERY CAPACITY ADDITIONS AND CLOSURES
(thousand barrels per day)

	2024	2025	2026	2027	2028	2029	2030	Total
Refining Capacity Additions and Expansions[1]								
OECD Americas	50	-222	-145	0	0	0	0	-367
OECD Europe	-120	-367	0	0	0	0	0	-367
OECD Asia Oceania	-120	0	0	0	0	0	0	0
Eurasia	70	127	50	0	0	0	0	177
Non-OECD Europe	0	0	0	0	0	0	0	0
China	310	389	273	0	-50	0	320	932
Other Asia	93	40	684	60	206	85	180	1255
Non-OECD Americas	0	15	0	0	0	115	0	130
Middle East	280	150	242	0	170	0	0	562
Africa	750	30	50	30	110	0	0	220
Total World	**1313**	**162**	**1154**	**90**	**436**	**200**	**500**	**2542**
Upgrading Capacity Additions[2]								
OECD Americas	0	-329	0	0	0	0	0	-329
OECD Europe	30	-36	0	0	0	0	0	-36
OECD Asia Oceania	-27	0	0	0	0	0	0	0
Eurasia	0	362	181	0	0	0	0	543
Non-OECD Europe	0	0	0	0	0	0	0	0
China	280	20	-183	0	-118	0	0	-281
Other Asia	5	232	196	217	57	40	0	742
Non-OECD Americas	0	0	0	0	85	0	0	85
Middle East	120	0	197	0	0	0	0	197
Africa	280	0	0	0	26	0	0	26
Total World	**688**	**249**	**391**	**217**	**50**	**40**	**0**	**947**
Desulphurisation Capacity Additions[3]								
OECD Americas	0	-557	0	0	0	0	0	-557
OECD Europe	38	-57	0	0	0	0	0	-57
OECD Asia Oceania	-109	0	0	0	0	0	0	0
Eurasia	0	110	0	0	0	0	0	110
Non-OECD Europe	0	0	0	0	0	0	0	0
China	376	162	-84	0	-42	0	0	36
Other Asia	97	198	317	153	162	0	0	830
Non-OECD Americas	0	0	-37	0	80	0	0	43
Middle East	0	0	261	0	0	0	0	261
Africa	263	0	0	0	43	0	0	43
Total World	**666**	**-144**	**457**	**153**	**244**	**0**	**0**	**710**

1 Comprises new refinery projects or expansions to existing Crude distillation units including condensate splitter additions. Assumes zero capacity creep.

Table 4a
CHANGES FROM OIL 2024
(thousand barrels per day)

	2024	2025	2026	2027	2028	2029	2030	Total
Refining Capacity Additions and Expansions[1]								
OECD Americas	170	-299	-145					-274
OECD Europe		-9						-9
OECD Asia Oceania								
Eurasia		127						127
Non-OECD Europe								
China	-140	329	-258		70		320	321
Other Asia		-220	72	-140	82	30	180	4
Non-OECD Americas					-115	115		
Middle East	110	20	10		70			210
Africa	60	-30	50	30	110			220
Total World	**200**	**-82**	**-271**	**-110**	**217**	**145**	**500**	**599**
Upgrading Capacity Additions[2]								
OECD Americas		-132						-132
OECD Europe								
OECD Asia Oceania	-27							-27
Eurasia		40						40
Non-OECD Europe								
China	106	20						126
Other Asia		-170		106				-64
Non-OECD Americas								
Middle East	40		55					95
Africa		-26		-29	26			-29
Total World	**119**	**-269**	**55**	**77**	**26**			**8**
Desulphurisation Capacity Additions[3]								
OECD Americas		-155						-155
OECD Europe								
OECD Asia Oceania	-109							-109
Eurasia		40						40
Non-OECD Europe								
China	74	162						236
Other Asia	22	-22						
Non-OECD Americas								
Middle East			-22					-22
Africa		-43		-38	43			-38
Total World	**-12**	**-18**	**-22**	**-38**	**43**			**-47**

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.

Table 4b
SELECTED REFINERY CRUDE DISTILLATION CHANGES LIST

Country	Project	Capacity (kb/d)	Year	Country	Project	Capacity (kb/d)	Year
OECD Americas				**Asia**			
Mexico	Dos Bocas	170	2025	China	Huajin Petchem (Panjin II)	320	2026
United States	Wilmington	-140	2025	China	Fujian Gulei Petchem (Gulei II)	320	2030
United States	Benicia	-150	2026	China	Zhenhai Refining and Chemical	240	2025
United States	Houston Lyondell	-260	2025	China	Yulong Petrochemical	210	2025
OECD Europe				China	Daxie Petrochemical	130	2025
Germany	Gelsenkirchen	-80	2025	China	Qilu Petchem	70	2028
Germany	Wesseling	-150	2025	China	Dalian (II) WEPEC	-200	2025
United Kingdom	Grangemouth	-140	2025	India	Panipat	200	2026
Middle East				India	Nagapattinam	180	2030
Bahrain	Sitra	120	2026	India	Barmer	180	2026
Iran	Persian Gulf Star (Bandar Abbas IV)	120	2025	India	Barauni, Bihar	130	2027
Iraq	Dhi Qar	100	2028	India	Numaligarh, Assam	120	2026
Iraq	Diwaniya	70	2028	India	Koyali, Gujarat	80	2026
Iraq	Missan	70	2026	India	Barauni, Bihar	-70	2027
NON-OECD Americas				Indonesia	Balikpapan (Ref Unit V)	100	2026
Brazil	RNEST	120	2029	Thailand	Sriracha I	100	2028
Africa							
Algeria	Hassi-Messaoud	110	2028				

Note: Only includes refinery capacity changes (additions or closures) above 70 kb/d. The data is rounded to the nearest 10 kb/d.

Table 5
WORLD ETHANOL PRODUCTION[1]
(thousand barrels per day)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
OECD North America	**1031**	**1049**	**1086**	**1074**	**1068**	**1076**	**1079**	**1089**	**1083**
United States	1002	1019	1055	1038	1029	1037	1040	1048	1042
Canada	29	30	31	36	38	39	40	41	41
OECD Europe	**112**	**114**	**123**	**130**	**140**	**149**	**164**	**183**	**193**
Austria	5	5	4	4	4	4	4	4	4
Belgium	12	12	12	12	12	12	12	12	12
France	20	21	22	23	24	26	28	30	30
Germany	13	12	14	14	15	16	16	16	16
Italy	0	1	2	4	4	4	4	4	4
Netherlands	10	10	11	12	16	20	23	38	46
Poland	7	7	8	9	10	11	12	14	15
Spain	9	10	10	10	14	15	15	15	15
UK	8	8	9	9	9	10	19	19	19
OECD Pacific	**4**	**4**	**4**	**4**	**6**	**9**	**10**	**13**	**13**
Australia	4	4	4	4	4	4	4	6	6
Total OECD	**1147**	**1167**	**1213**	**1209**	**1214**	**1235**	**1254**	**1284**	**1288**
Eurasia	0	0	0	0	0	0	0	0	0
Non-OECD Europe	2	2	1	1	2	2	2	2	2
China	66	68	86	87	87	87	87	88	93
Middle East	0	0	0	0	0	0	0	0	0
Africa	5	5	5	5	5	5	5	3	3
Other Asia	**112**	**127**	**156**	**181**	**202**	**219**	**243**	**259**	**278**
India	79	93	117	136	154	166	185	199	212
Indonesia	0	0	1	2	3	5	7	9	10
Malaysia	0	0	0	0	0	0	0	0	0
Philippines	7	7	7	7	7	7	7	7	7
Singapore	1	2	5	7	7	9	11	11	14
Thailand	25	25	26	29	30	32	32	33	34
Latin America	**565**	**646**	**678**	**693**	**721**	**752**	**774**	**810**	**820**
Argentina	20	20	18	21	21	22	22	23	23
Brazil	528	607	640	652	680	710	732	768	777
Colombia	6	7	7	7	7	7	7	7	7
Total Non-OECD	**751**	**849**	**927**	**967**	**1017**	**1065**	**1111**	**1163**	**1195**
Total World	**1898**	**2016**	**2140**	**2176**	**2231**	**2300**	**2364**	**2447**	**2483**

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.

Table 5a
WORLD BIODIESEL PRODUCTION[1]
(thousand barrels per day)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
OECD North America	**209**	**288**	**335**	**340**	**390**	**378**	**389**	**399**	**399**
United States	203	280	316	312	357	339	346	356	356
Canada	6	8	19	28	34	38	43	43	43
OECD Europe	**282**	**293**	**302**	**313**	**314**	**330**	**336**	**342**	**344**
Austria	6	10	11	11	11	11	11	11	11
Belgium	3	4	4	3	3	2	1	1	2
France	27	26	35	38	39	39	39	39	39
Germany	66	74	72	72	64	64	64	64	64
Italy	23	25	25	25	25	25	25	25	25
Netherlands	38	40	39	38	44	50	53	54	56
Poland	19	19	21	21	21	22	21	23	23
Spain	35	29	32	37	40	41	43	45	45
UK	13	13	13	13	13	13	13	13	13
OECD Pacific	**15**	**16**	**15**	**15**	**15**	**15**	**14**	**14**	**14**
Australia	0	0	0	0	0	0	0	0	0
Total OECD	**506**	**597**	**653**	**667**	**719**	**723**	**739**	**756**	**757**
Eurasia	0	0	0	0	0	0	0	0	0
Non-OECD Europe	15	17	13	13	14	14	14	14	14
China	42	43	43	37	37	40	43	36	36
Middle East	2	2	2	2	2	2	2	2	2
Africa	2	2	1	1	1	1	2	2	2
Other Asia	**270**	**303**	**351**	**393**	**421**	**451**	**470**	**482**	**497**
India	3	3	3	3	3	3	3	4	4
Indonesia	187	212	257	299	311	330	342	350	360
Malaysia	24	28	31	34	43	44	44	45	46
Philippines	4	4	4	5	6	7	7	7	8
Singapore	29	33	32	28	28	33	32	33	35
Thailand	23	23	24	24	29	35	40	42	44
Latin America	**163**	**165**	**196**	**229**	**250**	**260**	**280**	**286**	**291**
Argentina	37	19	24	29	29	29	30	30	30
Brazil	108	130	156	176	201	205	222	228	233
Colombia	13	13	13	13	13	13	14	14	14
Total Non-OECD	**492**	**532**	**607**	**677**	**727**	**769**	**811**	**822**	**842**
Total World	**999**	**1128**	**1260**	**1344**	**1445**	**1492**	**1550**	**1578**	**1599**

1 Biodiesel includes renewable diesel.

Table 6
OPEC+ Crude Oil and NGL[1] Capacities[2] to 2030

(million barrels per day)

	2024 Crude Capacity	2030 Crude Capacity	2024 NGL Capacity	2030 NGL Capacity
Algeria	0.99	0.91	0.45	0.42
Congo	0.27	0.23	0.01	0.01
Equatorial Guinea	0.06	0.05	0.04	0.02
Gabon	0.23	0.22	0.00	0.00
Kuwait	2.91	3.06	0.32	0.34
Nigeria	1.56	1.44	0.28	0.27
Saudi Arabia	12.1	12.3	1.76	2.73
UAE	4.30	5.02	0.95	1.21
Iraq	4.91	5.47	0.18	0.24
Iran	3.80	3.80	1.31	1.39
Libya	1.23	1.24	0.07	0.07
Venezuela	1.05	1.05	0.08	0.08
Total OPEC	**33.38**	**34.77**	**5.45**	**6.77**
Russia	9.53	9.47	1.40	1.40
Kazakhstan	1.83	1.94	0.33	0.36
Mexico	1.55	1.06	0.42	0.22
Azerbaijan	0.48	0.42	0.12	0.13
Oman	0.76	0.78	0.24	0.26
Other Non-OPEC OPEC+[3]	0.72	0.63	0.20	0.16
Total Non-OPEC	**14.88**	**14.31**	**2.70**	**2.53**
Total OPEC+	**48.26**	**49.07**	**8.15**	**9.30**

1 NGL capacities include condensates.

2 Capacity levels that can be reached within 90 days and sustained for an extended period.

3 Other Non-OPEC OPEC+ members includes Bahrain, Brunei, Malaysia, Sudan and South Sudan.

Annexes

Abbreviations and acronyms

ASEAN	Association of Southeast Asian Nations
ACE	Azeri Central East
BART	Bay Area Rapid Transit
Capex	capital expenditure
C5+	pentanes plus
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CDDs	cooling degree days
CIF	cost, insurance & freight
CDU	crude distillation unit (refinery)
CNOOC	China National Offshore Oil Company
CNPC	China National Petroleum Company
CNPE	National Energy Policy Council (Brazil)
CO_2	carbon dioxide
CTC	crude oil to chemicals (refinery)
CTL	coal-to-liquids
DUC	drilled but uncompleted well
EIA	US Energy Information Administration
E&P	exploration and production
EOR	enhanced oil recovery
ESG	environmental, social and governance
EU	European Union
EUAs	EU Allowances
EU-ETS	EU Emissions Trading System
EVs	electric vehicles
FAME	fatty acid methyl ester
FCC	fluid catalytic cracking unit (refinery)
FGP	future growth project
FPSO	floating production, storage and offloading
FID	final investment decision
FOB	free on board
Fracking	hydraulic fracturing
GDP	gross domestic product
GFC	Global Financial Crisis (2008)
GHG	greenhouse gas
GL	US Department of the Treasury's Office of Foreign Assets Control general license

GOR	gas-oil ratio
GTL	gas-to-liquids
HCK	hydrocracker (refinery unit)
HEV	hybrid electric vehicle
HDT	hydrotreating unit
HSFO	high sulphur fuel oil
HSR	high-speed rail
HVO	hydrotreated vegetable oil
IATA	International Air Transport Association
IMO	International Maritime Organization
ICE	internal combustion engine
IEA	International Energy Agency
IOC	international oil company
IP90	Initial 90-day average oil production
IRA	Inflation Reduction Act (United States)
ITP	Iraq-Türkiye Pipeline
ITT	Ishpingo-Tambococha-Tiputini
JOA	joint operating agreement
KMZ	Ku-Maloob-Zaap
KOC	Kuwait Oil Company
KRG	Kurdistan Regional Government
LCFS	low-carbon fuel standard (used in California)
LDV	light-duty vehicle
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTO	light tight oil
MER	market exchange rates
MERAM	maximising ethane recovery and monetisation project
MGO	marine gasoil
MPG	miles per gallon
MTBE	methyl tert-butyl ether
n-butane	normal butane
NBS	China’s National Bureau of Statistics
NGLs	natural gas liquids
NOC	national oil companies
NWE	Northwest Europe
OECD	Organisation for Economic Co-operation and Development
OFAC	US Department of the Treasury’s Office of Foreign Assets Control
OPEC	Organization of the Petroleum Exporting Countries
OPEC-12	Algeria, Congo, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates and Venezuela
OPEC+	Comprises 22 countries and includes the OPEC-12 member plus Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, Russia, South Sudan, and Sudan

Opex	operating expenses
PDH	propane dehydrogenation
PDVSA	Petróleos de Venezuela, S.A.
PE	polyethylene
PP	polypropylene
PPP	purchasing power parity
PSC	production sharing contract
PVC	polyvinyl chloride
RIGI	Régimen de Incentivo para Grandes Inversiones
RPK	revenue passenger kilometre
RNEST	Brazil Abreu e Lima Refinery
RPK	rail passenger kilometre
RRR	reserve replacement ratios
SAF	sustainable aviation fuel
SECA	Sulphur Emission Control Area
STEO	short term energy outlook (US EIA)
SUVs	sports utility vehicles
TAR	turnarounds (for major maintenance)
TfL	Transport for London
TMX	Trans Mountain Expansion Project
UAE	United Arab Emirates
UCO	used cooking oil
UN	United Nations
UNCTAD	United Nations Conference on Trade and Development
USD	US Dollar
USGC	United States Gulf Coast
US PADD	US Petroleum Administration for Defence District
US PADD 1	East Coast
US PADD 2	Midwest
US PADD 3	Gulf Coast
US PADD 4	Rocky Mountain
US PADD 5	West Coast
VGO	vacuum gasoil
VLSFO	very low sulphur fuel oil
VMT	vehicle miles travelled
WCS	Western Canadian Select crude
WCSB	Western Canada Sedimentary Basin
WFH	working-from-home
WTI	West Texas Intermediate
WTO	World Trade Organization

Units of measure

bbl	barrel (of oil)
b/d	barrels per day
boe	barrels of oil equivalent
GW	gigawatt
kb/d	thousand barrels per day
km	kilometre
mb/d	million barrels per day
mb	million barrels
MMscf/d	million standard cubic feet per day
Mt	million tonnes
Mt/yr	million tonnes per year
Mtpa	million tonnes per annum
tkm	tonne-kilometres
t	tonnes

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